UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. ____________**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARD PRC-012-2

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595 – facsimile

Charles A. Berardesco
Senior Vice President and General Counsel
Shamai Elstein
Senior Counsel
Andrew C. Wills
Associate Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
charles.berardesco@nerc.net
shamai.elstein@nerc.net
andrew.wills@nerc.net

Counsel for the North American Electric Reliability Corporation

August 5, 2016

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] the North American Electric Reliability Corporation ("NERC")[3] hereby requests Commission approval of the following[4]:

- Reliability Standard PRC-012-2 (Remedial Action Schemes) (**Exhibit B**);
- retirement of currently effective Reliability Standards PRC-015-1 (Remedial Action Scheme Data and Documentation) and PRC-016-1 (Remedial Action Scheme Misoperation);
- withdrawal of Reliability Standards PRC-012-1 (Remedial Action Scheme Review Procedure), PRC-013-1 (Special Protection System Database), and PRC-014-1 (Remedial Action Scheme Assessment);[5]

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1 16 U.S.C. § 824o (2012).

2 18 C.F.R. § 39.5 (2016).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the Federal Power Act on July 20, 2006 in Docket No. RR06-1-000. *See Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006), *order on reh'g and compliance,* 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 342 (D.C. Cir. 2009).

4 Unless otherwise designated herein, all capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary"), *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf.

5 NERC notes that the Commission has never approved or remanded the original versions of Reliability Standards RPC-012-0, PRC-013-0, and PRC-014-0, as the Commission deemed these standards "fill-in-the-blank" standards in Order No. 693. *See Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007). In its petition for approval of the revised definition of Remedial Action Scheme submitted on February 3, 2015, NERC submitted a new version of these standards but did not request Commission approval of these standards. Rather, NERC noted that it was submitting Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1 "for completeness." *Petition of the North American Electric Reliability Corporation for Approval of Revisions to the Definition of "Remedial Action Scheme" and Proposed Reliability Standards*, Docket No. RM15-13-000 at n. 6, 7, 8 (Feb. 3, 2015).

- Implementation Plan for PRC-012-2 (**Exhibit C**); and
- associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for PRC-012-2 (**Exhibits D**) (collectively, "NERC's Proposal").

NERC's Proposal was developed in Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes ("Project") and addresses all aspects of the design, approval, installation, and maintenance of Remedial Action Schemes ("RAS"). The NERC Board of Trustees adopted proposed Reliability Standard PRC-012-2, retirement of Reliability Standards PRC-015-1 (Remedial Action Scheme Data and Documentation) and PRC-016-1 (Remedial Action Scheme Misoperation), and withdrawal of previously unapproved Reliability Standards PRC-012-1 (Remedial Action Scheme Review Procedure), PRC-013-1 (Special Protection System Database), and PRC-014-1 (Remedial Action Scheme Assessment) on May 5, 2016.

NERC requests that the Commission approve NERC's Proposal as just, reasonable, not unduly discriminatory or preferential, and in the public interest. As required by Section 39.5(a) of the Commission's regulations,[6] this Petition presents the technical basis and purpose of proposed Reliability Standard PRC-012-2, a summary of the development history and the complete record of development (**Exhibit H**), and a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672 (**Exhibit G**).[7]

I. <u>EXECUTIVE SUMMARY</u>

RAS are, by definition, critical to preserving the reliability and integrity of the Bulk Electric System ("BES"), as they operate to institute "corrective actions that may include, but are

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6 18 C.F.R. § 39.5(a) (2016).

7 The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at PP 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s)."[8] The purpose of a RAS is to mitigate unacceptable System conditions subsequent to fault clearing, thereby reducing the risk of instability. Each RAS is unique in its location, design, and application, yet each RAS must be coordinated with other RAS and protection and control systems to govern BES reliability. Given the need for coordination of RAS, entities with a wide-area operational visibility must oversee the design, approval, installation, and maintenance of these important elements of the interconnected transmission network. In addition, entities with operational knowledge of RAS must perform routine tests after the operation or misoperation of a RAS to confirm its continued efficacy. Proposed Reliability Standard PRC-012-2, developed in Project 2010-05.3, addresses these considerations.

The standard drafting team for Project 2010-05.3 ("RAS SDT") developed proposed Reliability Standard PRC-012-2 by combining currently effective Reliability Standards PRC-015-1 and PRC-016-1 and unapproved Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1 into a single, consolidated, continent-wide Reliability Standard to address all aspects of RAS. Proposed Reliability Standard PRC-012-2 improves upon the existing standards as it removes ambiguity in NERC's original "fill-in-the-blank" standard by assigning responsibility to appropriate functional entities. The proposed standard also streamlines and consolidates the "piecemeal" RAS standards into one clear, effective Reliability Standard.

Specifically, proposed PRC-012-2 implements a centralized review process for each new or functionally modified RAS; obligates entities to complete periodic evaluations, tests, and operational analyses for all RAS; and requires the entity with a wide-area view to establish a

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[8] *NERC Glossary* (updated on June 24, 2016) at 84, *available at* http://www.nerc.com/files/glossary_of_terms.pdf.

database with pertinent information about each RAS. In doing so, the proposed standard vests the responsibility to administer the RAS review process and to create the RAS database with the Reliability Coordinator ("RC"). The standard requires the RAS-entity, which is the entity that "owns all or part of a RAS,"[9] to submit RAS information to the RC for review, address reliability issues identified by the RC, analyze operational performance of each RAS, and perform periodic functional tests of each RAS. Finally, the standard requires the Planning Coordinator ("PC") to periodically evaluate each RAS within its area to verify the continued effectiveness and coordination of the RAS. Proposed Reliability Standard PRC-012-2 establishes these obligations in nine requirements, as follows:

- Requirement R1 requires RAS-entities to submit certain information about each RAS that it intends to place into service to the RC where the RAS is located.
- Requirement R2 requires RCs that receive information about a RAS from a RAS-entity to review the RAS and provide feedback to the RAS-entity.
- Requirement R3 requires the RAS-entity that receives feedback from the RC regarding its RAS to resolve each reliability issue to obtain approval of the RAS from the RC.
- Requirement R4 requires the PC to perform a periodic evaluation of each RAS within its planning area, according to the type of RAS being evaluated.
- Requirement R5 requires each RAS-entity to perform an analysis of each RAS after operation or misoperation of the RAS and to provide the results of the evaluation to the reviewing RC.
- Requirement R6 requires the RAS-entity to develop and submit a Corrective Action Plan ("CAP") to the reviewing RC after learning of a deficiency with its RAS.
- Requirement R7 requires the RAS-entity to implement the CAP, update the CAP as necessary, and notify the RC when any changes are made to the CAP and when the CAP has been fulfilled.
- Requirement R8 requires the RAS-entity to test its RAS to verify continued operation on a timeline according to the type of RAS that is being tested.

[9] RAS-entities include Transmission Owners, Generator Owners, and Distribution Providers.

- Requirement R9 requires the RC to update its RAS database with information about each RAS on a yearly basis.

As explained in more detail below, proposed Reliability Standard PRC-012-2 integrates seamlessly with other relevant Reliability Standards and does not upend the established performance requirements in Reliability Standard TPL-001-4. Further, the proposed standard identifies a subset of RAS called "limited impact RAS" that represent those RAS that cannot "by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably dampened oscillations."[10] The proposed standard imposes more focused review requirements on RAS that have greater BES reliability impact and unique design.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to:[11]

Shamai Elstein*
Senior Counsel
Andrew C. Wills*
Associate Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
shamai.elstein@nerc.net
andrew.wills@nerc.net

Howard Gugel*
Director of Standards
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
Howard.Gugel@nerc.net

[10] *See* Proposed Reliability Standard PRC-012-2 at 7, 21 (attached herein as **Exhibit B**).

[11] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2016), to allow the inclusion of more than two persons on the service list in this proceeding.

III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[12] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power System, and with the duties of certifying an Electric Reliability Organization ("ERO") that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1) of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards.[13] Section 215(d)(5) of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard.[14] Section 39.5(a) of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes to become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes to be made effective.[15]

The Commission is vested with the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission also exercises oversight regarding proposals to retire Reliability Standards.[16] Pursuant to Section 215(d)(2) of the FPA[17] and Section 39.5(c) of the

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12 16 U.S.C. § 824o (2012).
13 *Id.* § 824o(b)(1).
14 *Id.* § 824o(d)(5).
15 18 C.F.R. § 39.5(a).
16 *See e.g.*, NERC *Standards Processes Manual*, at Section 4.19 of the NERC *Rules of Procedure*.
17 16 U.S.C. § 824o(d)(2).

Commission's regulations, "the Commission will give due weight to the technical expertise of the Electric Reliability Organization" with respect to the content of a Reliability Standard.[18]

B. NERC Reliability Standards Development Procedure

NERC's Proposal was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[19] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) and Appendix 3D (NERC Standard Processes Manual) of the Commission approved NERC Rules of Procedure.[20]

In its order certifying NERC as the Commission's ERO, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards,[21] and thus satisfy certain of the criteria for approving Reliability Standards.[22] The ANSI-accredited development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders, and stakeholders must approve, and the NERC Board of Trustees must adopt a Reliability Standard before NERC submits the Reliability Standard to the Commission for approval.

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18 18 C.F.R. § 39.5(c)(1).

19 *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006) ("Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.").

20 The NERC *Rules of Procedure* are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC *Standard Processes Manual* is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

21 116 FERC ¶ 61,062 at P 250.

22 Order No. 672 at PP 268, 270.

C. Procedural History of Reliability Standard PRC-012-2

In Order No. 693, the Commission evaluated 107 Reliability Standards, including Reliability Standards PRC-012-0 (Special Protection System Review Procedure), PRC-013-0 (Special Protection System Database), PRC-014-0 (Special Protection System Assessment), PRC-015-0 (Special Protection System Data and Documentation), and PRC-016-0 (Special Protection System Misoperations).[23] While the Commission approved Reliability Standard PRC-015-0 and PRC-016-0 as mandatory and enforceable in Order No. 693, the Commission neither approved nor remanded Reliability Standards PRC-012-0, PRC-013-0, and PRC-014-0 but identified these as "fill-in-the-blank" standards with an inadequate basis for approval.[24] Along with the abovementioned standards, the Commission also approved the NERC Glossary, which included definitions for the terms "Special Protection System" ("SPS") and "Remedial Action Scheme."[25] As these terms were used interchangeably across Interconnections and the ERO Regions, NERC developed the definitions approved in Order No. 693 to ensure that both terms could be used in reference to the same equipment.

In early 2010, after several years' experience implementing these standards and based on industry input, NERC initiated Project 2010-05 to address issues associated with RAS and SPS. NERC initiated the project to address the inconsistent usage of the terms RAS and SPS across Interconnections and NERC Regions, and to modify the standards to improve the monitoring of BES Protection System events by identifying and correcting the causes of Misoperations. Based on industry input, NERC subdivided the work in Project 2010-05 into two phases, Project 2010-

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[23] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[24] *Id*. at PP 1520, 1524, 1528, 1533, and 1539.

[25] *Id.* at P 1893.

05.1 and Project 2010-05.2, to address issues associated with Misoperations of Protection Systems ahead of the work associated with SPS and RAS.[26] The work in Project 2010-05.1 culminated in the development of proposed Reliability Standard PRC-004-3 (Protection System Misoperation Identification and Correction) and the proposed revised definition of "Misoperations." On September 15, 2014, NERC submitted proposed Reliability Standard PRC-004-3 (Protection System Misoperation Identification and Correction) and the NERC Glossary definition for the term "Misoperations" to the Commission in Docket No. RD14-14-000.[27] The Commission approved PRC-004-3 and the definition of Misoperations on May 13, 2015.[28]

While work on Misoperations continued in Project 2010-05.1, NERC simultaneously began its effort to improve the identification and assessment of SPS and RAS in Project 2010-05.2. In the Standards Authorization Request for Project 2010-05.2, NERC stated that the project would address the RAS and SPS definitions, the Commission's Order No. 693 findings, and four recommendations related to the "identification and coordination of SPS from the joint FERC-NERC inquiry of the September 2011 Southwest Blackout Event."[29] In the initial stages of development for this project, NERC realized the extent of the work necessary to revise associated definitions and Reliability Standards and to develop a consistent, uniform, and continent-wide RAS-specific Reliability Standard, and further divided Project 2010-05.2 into

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26 *See* NERC Standards Committee Meeting Minutes (Jun. 9, 2011), available at http://www.nerc.com/docs/standards/sc/sc_060911m_package.pdf.

27 *Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard PRC-004-3*, Docket No. RD14-14-000 (filed on Sept. 15, 2014).

28 *Order Approving Reliability Standard*, 151 FERC ¶ 61,129 (May 13, 2015).

29 *Standard Authorization Request for Project 2010-05.2* (Feb. 12, 2014), accessible online at http://www.nerc.com/pa/Stand/Prjct201005_2SpclPrtctnSstmPhs2/SPS_SAR_02042014.pdf (explaining that the project would address the Commission's decision in Order No. 693 to neither approve nor remand Reliability Standards PRC-012-0, PRC-013-0, and PRC-014-0, and that the project would address four recommendations from the FERC-NERC inquiry of the September 2011 Southwest Blackout Event. Notably, the recommendations from the FERC-NERC inquiry, which were related to the identification and coordination of SPS, were addressed during the development of the revised definition of RAS, submitted to the Commission in Docket No. RM15-13-000.).

two projects. NERC commenced development in these projects, Project 2010-05.2 and Project 2010-05.3, to revise the definition of RAS and to develop a Reliability Standard addressing issues associated with RAS, respectively.

In 2011, NERC began development of a revised definition of RAS in Project 2010-05.2 based on the findings of a System Protection and Control Subcommittee ("SPCS") and System Analysis and Modeling Subcommittee ("SAMS") Technical Report titled "Special Protection Systems (SPS) and Remedial Action Schemes (RAS): Assessment of Definition, Regional Practices, and Application of Related Standards" ("SPCS/SAMS Report").[30] The SPCS/SAMS Report noted the lack of clarity of the definition of SPS, the inconsistent use of the terms SPS and RAS across the eight Regions, and the impact this inconsistent usage would have on identification. Using the information in the SPCS/SAMS Report, the standard drafting team for Project 2010-05.2 developed an improved, revised definition of RAS with more detail than the existing definition of SPS, including a refined core definition and specific inclusions and exclusions. NERC submitted the revised definition and several revised Reliability Standards incorporating the new term, including Reliability Standards PRC-015-1 and PRC-016-1,[31] on February 3, 2015.[32] On November 19, 2015, the Commission issued Order No. 818 approving, among other things, the revised RAS definition.[33]

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30 *See Petition of the North American Electric Reliability Corporation for Approval of Revisions to the Definition of "Remedial Action Scheme" and Proposed Reliability Standards* ("RAS Petition"), Docket No. RM15-13-000 at Exhibit G (filed on Feb. 3, 2015).

31 NERC notes that the only substantive revisions made in the revised standards, PRC-015-1 and PRC-016-1, were to transition from use of the term "Special Protection System" to the newly defined term "Remedial Action Scheme."

32 RAS Petition at n. 6, 7, 8 (including revisions to Reliability Standards PRC-012-0, PRC-013-0, and PRC-014-0 to incorporate the term "Remedial Action Scheme," and noting that because the Commission neither approved nor remanded these standards in Order No. 693, NERC was not requesting approval of these standards. Rather, NERC noted that it was submitting Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1 "for completeness.").

33 *Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards; Revisions to the Definition of "Remedial Action Scheme" and Related Reliability Standards* (Order No. 818), 153 FERC ¶ 61,228 (2015).

NERC initiated Project 2010-05.3 in 2015 to address all other aspects of RAS and SPS in the RAS/SPS-related Reliability Standards. The RAS SDT concluded its work with the development of proposed Reliability Standard PRC-012-2 (Remedial Action Schemes), which is the subject of this Petition, and a revised NERC Glossary definition of SPS. NERC developed the revised definition of SPS to complete the transition from the term "Special Protection System" to "Remedial Action Scheme" initiated by NERC in Project 2010-05.2. As industry approved the revised definition of SPS before proposed PRC-012-2, NERC submitted the revised definition of SPS to the Commission in a separate petition on May 11, 2016.[34] On June 23, 2016, the Commission issued a delegated letter order approving the revised definition of SPS.[35]

Industry approved proposed Reliability Standard PRC-012-2 in a final ballot ending on April 29, 2016.[36] The proposed standard, which addresses the implementation of all new and functionally modified RAS as well as the periodic review of all in-service RAS, combines two Commission approved standards and three previously unapproved standards deemed by the Commission in Order No. 693 to be "fill-in-the-blank" standards. The NERC Board of Trustees approved proposed Reliability Standard PRC-012-2 on May 5, 2016.

IV. JUSTIFICATION FOR APPROVAL

NERC's Proposal represents the technical findings of the RAS SDT based on its review of the Commission's findings related to SPS and RAS in Order No. 693, the recommendations

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[34] *Petition of the North American Electric Reliability Corporation for Approval of the Revised Definition of Special Protection System*, Docket No. RD16-5-000 (May 11, 2016).

[35] *N. Am. Elec. Reliability Corp.*, Docket No. RD16-5-000 (June 23, 2016) (unpublished letter order).

[36] See NERC, *Standard Announcement*, Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS) PRC-12-2 and Definition of "Special Protection System, available at http://www.nerc.com/pa/Stand/Prjct201005_3RmdialActnSchmsPhase3ofPrtctnSystmsDL/2010-05.3_PRC-012-2_FB_Results_Word_Announce_05032016.pdf.

related to SPS and RAS from the FERC-NERC inquiry[37] of the September 2011 Southwest Blackout Event, several years' experience monitoring and evaluating SPS and RAS, and stakeholder comments throughout the Project. The purpose of proposed Reliability Standard PRC-012-2 is to "[t]o ensure that [RAS] do not introduce unintentional or unacceptable reliability risks to the [BES]." The nine Requirements of proposed PRC-012-2 accomplish the stated purpose by addressing planning, coordination, design, review, assessment, and documentation of each RAS. The proposed standard, which establishes a continent-wide RAS review and maintenance program, should ensure that each RAS integrates seamlessly and effectively into the BES and contributes to reliability by performing its intended function as designed.

Proposed Reliability Standard PRC-012-2 is intended to supersede unapproved Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1, as well as retire and replace currently effective Reliability Standards PRC-015-1 and PRC-016-1.[38] NERC has developed a concise comparison of the requirements of several currently effective and pending Reliability Standards and the proposed Reliability Standard PRC-012-2 in the Mapping Document for PRC-012-2, attached herein as **Exhibit E**. Proposed Reliability Standard PRC-12-2 represents substantial improvements over these Reliability Standards, as it streamlines and consolidates

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[37] *See Standards Authorization Request for Project 2010-05.2—Special Protection System* (Feb. 12, 2014), *available at* http://www.nerc.com/pa/Stand/Prjct201005_2SpclPrtctnSstmPhs2/SPS_SAR_02042014.pdf; *see also Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations* (April 2012), *available at* http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.

[38] For purposes of this Petition, NERC treats Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1 as if they were part of NERC's original suite of Reliability Standards. These "version 1" Reliability Standards were revised during the development of revisions to the term RAS by changing the term "Special Protection System" to "Remedial Action Scheme." While noting that the Commission would not approve Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1, NERC submitted these standards to the Commission in the RAS Petition "for completeness." *See* RAS Petition at n. 6, 7, 8.

existing requirements, corrects the applicability of previously unapproved standards, and implements a continent-wide RAS review program.

The following sections provide: (i) an explanation of the applicability of Reliability Standard PRC-012-2, (ii) a requirement by requirement justification of each of the nine Requirements in proposed Reliability Standard PRC-012-2, including an explanation for use of the term "limited impact" RAS to account for the different impacts on reliability of those RAS, and an explanation of the interplay between PRC-012-2 and TPL-001-4, (iii) a summary of the enforceability of PRC-012-2, and (iv) a justification for the proposed retirements and withdrawals associated with the development of PRC-012-2.

A. Applicability

Proposed Reliability Standard PRC-012-2 applies to RCs, PC, and RAS-entities. As the RC maintains the requisite "[w]ide-[a]rea" perspective to "prevent or mitigate emergency operating situations in both next-day analysis and real-time operations,"[39] the RC is the appropriate entity to review each new or functionally modified RAS in its respective area to ensure area-wide reliability and to collect pertinent RAS data in a RAS database. This perspective allows the RC to evaluate interactions among separate RAS and other protection and control systems. Further, given the RC's unique responsibility and the typical business arrangement of an RC with entities within the RC area, the RC is the entity least likely to have conflicts of interest, including business relationships, with RAS-entities, PCs, and other relevant entities.

[39] *NERC Glossary* (updated on June 24, 2016) at 81, *available at* http://www.nerc.com/files/glossary_of_terms.pdf.

The PC is the functional entity responsible for assessing the "longer-term reliability" within its area by coordinating, facilitating, integrating, and evaluating transmission facility and service plans within its respective area.[40] As such, the PC is the appropriate functional entity to maintain oversight of each RAS in its PC area so that it continues to function as planned. The PC already fulfills responsibilities similar to the RAS modeling and studies required under proposed PRC-012-2 and can thus perform the responsibilities of PRC-012-2 seamlessly.

Finally, in recognition of the need for a term to describe all entities that are responsible for a RAS, NERC developed the term "RAS-entity" to describe the Transmission Owner(s), Generator Owner(s), or Distribution Provider(s) that "owns all or part of a RAS."[41] This broad term captures each entity involved in RAS ownership. Outside of agreements among responsible entities regarding compliance with applicable standards, the standard remains applicable to each entity that owns all or part of a RAS. Taken together, the proposed Requirements obligate the RC, PC, and RAS-entity to share resources and collaborate to the extent necessary to establish a continent-wide RAS program.

B. Requirement by Requirement Justification

Proposed Reliability Standard PRC-012-2 consists of nine Requirements that individually contribute to its stated purpose. As reflected in **Exhibit G**, NERC's Proposal satisfies the Commission's criteria in Order No. 672 and is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The subsections below provide additional justification and information regarding each Requirement or group of Requirements, as follows:

i) three Requirements obligating the RC to engage in a RAS review process (Requirements R1, R2, and R3);

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40 *See id* at 69; *see also Reliability Functional Model* (Version 5) at 22.

41 Section 4 of Reliability Standard PRC-012-2 (see **Exhibit B**).

ii) one Requirement mandating the PC to engage in a periodic review of each RAS (Requirement R4);

iii) one Requirement ensuring that the RAS-entity continuously reviews its RAS upon operation or misoperation (Requirement R5);

iv) two Requirements enacting a process for RAS-entities to address issues with each RAS identified by the RC in its RAS review (Requirements R6 and R7);

v) one Requirement obligating the RAS-entity to perform a periodic functional test for each of its RAS (Requirement R8); and

vi) one Requirement mandating the RC to establish a RAS database (Requirement R9).

i) <u>Requirements R1, R2, and R3</u>

R1. Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R2. Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R3. Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Proposed Requirements R1, R2, and R3 establish an RC review process for each new or functionally modified RAS that must be completed before a RAS-entity places a RAS into service. The RAS review is the first step towards evaluating and coordinating RAS across the RC area, including those in neighboring RC areas, to ensure that RAS do not introduce "unintentional or unacceptable reliability risks" into the BES. As noted above, the RC is the appropriate entity to perform the RAS review because the RC has a wide-area reliability perspective and awareness of reliability issues in neighboring RC areas.

Under Requirement R1, a RAS-entity must provide the reviewing RC with the data included in Attachment 1 to the standard before placing the "new or functionally modified" RAS into service or retiring an existing RAS. Attachment 1 identifies a variety of targeted, pertinent information regarding the RAS design, function, and operation that the RC needs to perform the RAS review. As such, the reviewing RC would only review particularized information deemed relevant for purposes of maintaining reliability. NERC designed Attachment 1 to eliminate any ambiguity in the information that a RAS-entity must submit to the RC for review to make a determination about whether the RAS may be approved.

Just as the RC must review new RAS to determine whether the new device would impact operations once implemented, the RC must also review RAS that have been "functionally modified" to ensure that any changes made to the RAS do not introduce new issues into the BES. According to footnote 2 of Attachment 1 and footnote 4 of Attachment 2, a RAS is deemed "functionally modified" if the RAS-entity experiences any of the following:

i) changes to System conditions or Contingencies monitored by the RAS;

ii) changes to the actions that the RAS is designed to initiate;

iii) changes to RAS hardware beyond hardware replacement that matches the original functionality of existing components;

iv) changes to RAS logic beyond correcting existing errors; or

v) addition or removal of redundancy levels.[42]

When an entity submits a "functionally modified" RAS for review, the RC is only required to review details of the proposed modifications; however, the submitting RAS-entity must provide a summary of existing functionality in Attachment 1 to provide sufficient context

[42] NERC provides additional information about what constitutes a functional modification in the *Reliability Standard PRC-12-2 Remedial Action Schemes Question & Answer Document*, attached herein as **Exhibit F**.

for the RAS modifications to allow the RC to perform an abbreviated review of the RAS. After the RAS-entity completes and delivers Attachment 1 to the reviewing RC, the RC must begin its comprehensive review of the affected RAS pursuant to proposed Requirement R2.

Under Requirement R2, the RC is required to perform a RAS review in accordance with Attachment 2 within four months of receiving a completed Attachment 1, or on an otherwise agreed upon schedule. Attachment 2 is a detailed checklist of criteria that the RC must use to identify design and implementation aspects of the RAS that are critical to an effective RAS review framework. By requiring the RC to perform the RAS review according to Attachment 2 (*Reliability Coordinator RAS Review Checklist*) of proposed PRC-012-2,[43] Requirement R2 establishes a comprehensive, consistent review process. The RC, when performing the review, may request assistance from other parties that have access to relevant information about the RAS, such as the PC or regional technical groups; however, the RC is ultimately responsible for compliance with Requirement R2. This delineation of responsibility, which holds the RC responsible as an independent party, helps to mitigate any conflict of interest that may exist due to 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.

In observance of the time needed to complete each review, the RC must perform the Attachment 2 review within four full calendar months, or on an otherwise negotiated basis. This periodicity is consistent with industry practice and provides adequate time for a complete review, and it includes additional flexibility for unique or unforeseen circumstances. Upon completion of the review, the RC must provide the RAS-entity with the results of its RAS review identifying

[43] Examples of issues that the RC may identify with each RAS include, but are not limited to, a lack of dependability, security, or coordination. Notably, the *Reliability Coordinator RAS Review Checklist* warns that the "RC review is not limited to the checklist items and the RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS."

reliability issues that must be resolved before the RAS-entity can place the RAS into service. The RAS-entity may place the RAS into service only when the reviewing RC's feedback to each RAS-entity indicates either that no reliability issues were identified during the review or that all reliability issues identified by the RC have been resolved to the satisfaction of the reviewing RC, as required under Requirement R3.

Requirement R3 requires the RAS-entity to resolve any reliability issues with the RAS identified by the RC before the RAS-entity places the RAS into operation. While there is no explicit timeframe for the RAS-entity and the RC to resolve the issues identified by the RC and to approve the RAS, respectively, the RAS-entity and the RC would be motivated to do so on a timely basis. The RAS-entity would not be permitted to place a RAS in service unless the RAS-entity has taken all remedial steps prescribed by the RC as a result of the RAS review. Because the RAS-entity is the party requesting approval of a RAS to be placed into service and would want approval as soon as possible, the RAS-entity is incentivized to address any RC concerns as quickly as possible. Similarly, the RC, the functional entity with significant responsibility for maintaining BES reliability in its area, is motivated to approve new or modified RAS that improve BES reliability. As discussed above, because RAS play an important role in helping to ensure reliable operations, an RC would thus act with expediency to approve a RAS that improves reliability to continue fulfilling its responsibility. Accordingly, a specific period for remediation of the identified issues and approval of each RAS is unnecessary.

ii) <u>Requirement R4</u>

R4. Each Planning Coordinator, at least once every five full calendar years, shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Perform an evaluation of each RAS within its planning area to determine whether:

4.1.1. The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed.

4.1.2. The RAS avoids adverse interactions with other RAS, and protection and control systems.

4.1.3. For limited impact[44] RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

4.1.4. Except for limited impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following:

4.1.4.1. The BES shall remain stable.
4.1.4.2. Cascading shall not occur.
4.1.4.3. Applicable Facility Ratings shall not be exceeded.
4.1.4.4. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.
4.1.4.5. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

4.1.5. Except for limited impact RAS, 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 is designed.

4.2. Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.

The purpose of Requirement R4 is to ensure that there are periodic reviews of a RAS after the RAS-entity places it in service to confirm that the RAS continues to function as planned and does not adversely affect reliable operations or introduce any "unintentional or unacceptable reliability risks" into the BES.[45] After the RC has reviewed and approved a RAS pursuant to Requirements R1-R3, and the RAS-entity places it into service, the RAS-entity may experience

[44] "A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations." *See* Reliability Standard PRC-012-2 (attached herein as **Exhibit B**).

[45] The purpose of Requirement R4 is consistent with the purpose of proposed Reliability Standard PRC-012-2, which is "[t]o ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES)."

changes in System topology or operating conditions that necessitate an additional evaluation of affected RAS. As such, Requirement R4 creates an affirmative obligation on the PC to conduct periodic evaluations of each in-service RAS.

As discussed above, because the PC is the entity that "coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems" with a wide area planning perspective, the PC is the appropriate entity to conduct this continuous oversight of each in-service RAS pursuant to Requirement R4. The PC is responsible for conducting the evaluation of RAS in its area under Requirement R4. If the RAS crosses PC boundaries, each affected PC is responsible under Requirement R4 for conducting either individual evaluations or participating in a coordinated evaluation.[46]

The PC must evaluate each RAS in its area every five years. As provided in the Implementation Plan associated with proposed PRC-012-2, the PC must complete initial performance of this requirement for each new and functionally modified RAS within five years after the date of RC approval of the RAS.[47] For each existing RAS, the PC must complete initial performance of this requirement within five years after the effective date of the proposed standard. Five years is an appropriate periodicity for PC review of each RAS as it corresponds to the five-year performance period required under Reliability Standards PRC-006, PRC-010, and PRC-014. These standards require responsible entities to perform effectiveness evaluations on remedial equipment similar to the evaluation required under Requirement R4 of proposed PRC-012-2, so alignment with PRC-006, PRC-010, and PRC-014 would improve consistency and

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46 *See* Reliability Standard PRC-012-2 at 34 (Technical Justification).

47 NERC notes that five (5) years is the maximum allowable interval in between evaluations under Requirement R4, so even if a RAS is functionally modified during the initial five (5) year period, the responsible entity must continue to fulfill the performance obligation within the initial five (5) year period. *See* Implementation Plan for PRC-012-2 (**Exhibit C**) at 2.

would streamline various evaluation processes.[48] While this is the maximum allowable interval between PC reviews, the PC may evaluate a RAS more frequently if necessary in response to a new generator interconnection, transmission system changes, changes in load, etc. This periodic RAS evaluation should lead the PC to provide one of the following determinations: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

Using a risk-based approach, the nature of the evaluation mandated by Requirement R4 depends on whether the relevant RC has designated the RAS as a "limited-impact RAS." Attachment 2 of PRC-012-2 provides that RCs may designate a RAS as "limited impact" if the RC determines that the RAS is incapable of causing significant adverse BES reliability impacts. As described in footnote 1 of Reliability Standard PRC-012-2, a "limited impact RAS" is a RAS that "cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations."

The proposed standard imposes more detailed evaluation requirements on RAS that are not designated as "limited impact," consistent with the greater risks they present to BES reliability. For non-limited impact RAS, the PC must perform an evaluation consistent with all the subparts of Requirement R4 except Part 4.1.3. The evaluation requirements contained in Parts 4.1.1, 4.1.2, 4.1.4, and 4.1.5, obligate the PC to confirm that:

- the RAS mitigates the System condition(s) or Contingency(ies) for which it was designed;

[48] Reliability Standard PRC-010-2 requires the PC and TP is required to perform an effectiveness evaluation of its UVLS program once every five years. Reliability Standard PRC-006-2 requires the PC to conduct a UFLS assessment every five years to ensure compliance with certain criteria. Reliability Standard PRC-014-1 (which the Commission has not approved or remanded) requires the responsible entity to assess each RAS in its respective area.

- the RAS avoids adverse interactions with other RAS, and protection and control systems;
- when inadvertent operation of the RAS occurs, the BES remains stable, cascading does not occur, ratings are not exceeded, voltages are within limits, and voltage responses are within limits; and
- a single component failure in the RAS does not prevent the BES from meeting requirements in TPL-001-4 as required for the events and conditions for which the RAS is designed.

For limited impact RAS, the PC must only conduct an evaluation consistent with Parts 4.1.1, 4.1.2, and 4.1.3 to confirm that: (1) the RAS mitigates the System condition(s) or Contingency(ies) for which it was designed; (2) the RAS avoids adverse interactions with other RAS, and protection and control systems; and (3) the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. The SDT determined that the additional elements of the evaluations for non-limited impact RAS provided in Parts 4.1.4 and 4.1.5 should not be required for "limited impact" RAS given that they present a lower risk to BPS reliability, as further discussed below.

The following discussion provides (i) additional technical justification for distinguishing "limited impact" RAS from all other RAS, and (ii) an explanation of the relationship between Requirement R4 of proposed PRC-012-2 and currently-effective Reliability Standard TPL-001-4.

a) Limited Impact RAS

This section provides an explanation of: (1) the need for the "limited impact" RAS designation; (2) the process by which the RC may designate a RAS as "limited impact; and (3) the process by which the PC is obligated to periodically evaluate whether the "limited impact" RAS should continue to be designated as limited impact.

Need for Limited Impact Designation: Each RAS is unique in geography, purpose, design, and complexity. Depending on these characteristics and the problems that the RAS are designed to mitigate, there may be significant differences amongst RAS as to their potential impact on the reliability of the BES. A RAS would have a small impact if the RAS-entity designs or implements the RAS such that it cannot, by inadvertent operation or failure to operate, cause or contribute to major reliability issues. While these smaller impact RAS are important for reliability, they are technically incapable of causing critical issues that could impact operations across a large area.

An example of a limited impact RAS is a scheme applied on an interconnection between two utilities, with one side of the tie consisting of a 230 kV line in parallel with a long 115 kV line that does not provide significant support to the intertie. The other side of the intertie is a 345 kV line. Depending on pre-contingency magnitude and direction of flow, the scheme is armed to do one of the following upon loss of the 230 kV line: (i) nothing;[49] (ii) switch a shunt reactor; or (iii) open the 345 kV tie. This RAS mitigates voltage deviation greater than 5%, but it is not designed to address voltage level, overload, Cascading, or other serious operational issues that would exclude the RAS from being "limited impact."

In contrast, an example of a non-limited impact RAS is one that separates the WECC system into two planned islands following loss of three parallel 500 kV lines connecting Oregon and California. This islanding scheme is armed depending on pre-event flows. In addition to islanding and other actions, the RAS may drop more than 2000 MW of generation, a similar amount of load shedding, and switch shunt reactive devices at multiple locations across most of the WECC system. The non-limited impact RAS mitigates problems including Cascading,

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[49] There are some system conditions for which no action is required.

unplanned islanding, angular and voltage instability and possible collapse of major parts of the System, each result substantially more critical than those mitigated by the limited impact RAS described above.

Recognizing the significant differences amongst RAS and the need to focus industry resources on those RAS that present greater risk to BES reliability, proposed Reliability Standard PRC-012-2 (1) establishes a process whereby the RC may designate a RAS as “limited impact” based on its characteristics, and (2) subjects limited impact RAS to a different set of requirements than RAS that are not limited impact to account for the varying levels of risks presented. The purpose of the designation is thus to maintain the risk-based nature of NERC Reliability Standards by requiring applicable entities to review RAS in a manner that is commensurate with the potential impact of the RAS on reliability.

Process for RC Designation of Limited Impact RAS: As noted above, under Requirement R1, prior to placing a RAS into service, the RAS-entity must submit the information contained in Attachment 1 to the RC for its review. In completing Attachment 1, the RAS-entity must identify whether the RAS is limited impact and provide the reviewing RC with technical justification establishing that the RAS is “limited impact.” Pursuant to Requirement R2, the reviewing RC must review the RAS based on criteria in Attachment 2, which requires the RC to consider the studies and information provided to the RC in Attachment 1 and determine whether the RAS identified by the RAS-entity should be designated as a “limited impact” RAS.

The RC would designate the RAS as a limited impact RAS if it determines, based on its review under Requirement R2, that the RAS “cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations."[50] When the RC agrees that the RAS-entity has addressed each of the reliability issues identified by the RC, the RC would approve the RAS, and if applicable, would designate it as "limited impact." The RAS-entity may place the RAS into service only after the RC is satisfied that all reliability issues have been addressed.

Diversity among the different types, functions, and placements of RAS make it difficult to establish a bright line rule for correctly and consistently identifying (existing and future) RAS that are "limited impact" and RAS that are not "limited impact." As such, proposed Reliability Standard PRC-012-2 requires the RC to make this determination on a case-by-case basis based on its review of the RAS. The RC is already required to approve a RAS based on various criteria under Requirement R2, and the RC has the benefit of having all technical criteria included in Attachment 1 for each RAS. Further, the RC is the appropriate entity to designate a RAS as "limited impact" as it has the wide-area view and understanding of the BES to determine whether a RAS "cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations."

Prior to development of proposed PRC-012-2, two NERC Regions, the Northeast Power Coordinating Council ("NPCC") and the Western Electric Coordinating Council ("WECC"), used individual RAS classification regimes to identify RAS that would meet similar criteria described as "limited impact" in proposed PRC-012-2. Specifically, the standard drafting team identified the Local Area Protection Scheme ("LAPS") classification in WECC and the Type III

50 As the term "BES" in the explanation of "Limited Impact" modifies each of the conditions referenced therein, "Limited Impact" RAS may not contribute to BES Cascading, BES uncontrolled separation, BES angular instability, BES voltage instability, BES voltage collapse, or unacceptably dampened BES oscillations.

classification in NPCC as consistent with the "limited impact" designation. A RAS that was implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC, and that is classified as either a LAPS by WECC or a Type III by NPCC, would be considered a "limited impact" RAS for purposes of PRC-012-2 initially. Accordingly, if WECC or NPCC has designated a RAS as "limited impact," the RC does not need to designate the RAS as "limited impact" through an initial review because the RAS is already in service and was subject to the relevant regional review process. Notably, any LAPS or Type III RAS is still subject to the periodic PC evaluation to confirm that the RAS still meets the "limited impact" qualifications under Part 4.1.3. As provided in the Implementation Plan, the PC must conduct an evaluation within 5 years of the effective date of the proposed Reliability Standard. If PC finds that a LAPS or Type III RAS is not a limited impact RAS, the LAPS or Type III RAS will no longer retain that designation. NERC has provided a series of examples of currently active LAPS and Type III schemes in **Exhibit A**.

PC Evaluation of Limited Impact RAS: While the RC is responsible for performing the initial designation of limited impact RAS, Requirement R4 of proposed PRC-012-2 requires the PC to review the limited impact RAS to confirm its continued status as "limited impact" as part of its periodic evaluation. Specifically, Requirement R4, Part 4.1.3 explicitly requires the PC to evaluate all "limited impact" RAS to verify that the RAS does not, "by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations." The PC may use its discretion as to the method used to evaluate each limited impact RAS.

The PC is the appropriate entity to verify that a RAS continues to be "limited impact" because the PC maintains a wide-area planning perspective to determine whether the designation still applies, and the PC can provide the results of the evaluation to each impacted TP, PC, RC, and RAS-entity. If the PC determines that the RAS maintains this qualification, the limited impact designation remains applicable; however, if the PC determines that this is no longer applicable to the RAS, then the RC may choose to withdraw the limited impact designation at which point the RAS would become subject to the single component failure and malfunction tests under R4.1.4 and R4.1.5. All limited impact RAS, whether designated by the RC or under a preexisting regional process described above, would be periodically reviewed under the verification provision in Requirement R4.

RAS designated as "limited impact" RAS are not subject to the single component malfunction and failure evaluations in Parts 4.1.4 and 4.1.5 of proposed Reliability Standard PRC-012-2, respectively. Under Requirement R4, Part 4.1.4, the PC must review individual RAS components to determine whether an inadvertent operation of a RAS would have a BES-wide impact (i.e., Cascading, failure to meet Applicable Facility Ratings, etc.). Similarly, Requirement R4, Part 4.1.5 requires the PC to review single component failures in RAS to confirm that the failure does not prevent the BES from meeting the performance requirements of TPL-001-4. RAS that are "limited impact" cannot, by inadvertent operation or failure to operate, "cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations." In its initial review of the RAS, the RC designated the RAS as limited impact because it met these qualifications. As limited impact RAS cannot, by definition, fail the evaluations in Requirement R4, Parts 4.1.4 and 4.1.5, the PC does not need to perform the inadvertent operation analysis or single component failure analysis under these parts. Accordingly, requiring a limited impact RAS to meet these tests would provide little to no benefit to BES reliability.

b) Relationship to Reliability Standard TPL-001-4

Requirement R4 of proposed PRC-012-2 does not supersede or modify PC responsibilities under Reliability Standard TPL-001-4 but works with Reliability Standard TPL-001-4 to require the inadvertent operation of certain RAS to meet, at a minimum, performance requirements common to all planning events listed in TPL-001-4.

Reliability Standard TPL-001-4 sets forth Transmission system planning performance requirements for various System conditions and probable Contingencies. Table 1 of Reliability Standard TPL-001-4 explains the specific performance requirements that a RAS must meet according to the Contingency or System condition. Similarly, under Parts 4.1.1, 4.1.2, 4.1.3, 4.1.4, and 4.1.5 of Requirement R4 of proposed PRC-012-2, the PC must complete an evaluation of each RAS to ensure that it operates appropriately and that it meets certain performance criteria. While the requirements under TPL-001-4 and PRC-012-2 are similar, proposed PRC-012-2 introduces the possibility of RAS failure to operate and RAS inadvertent operation, matters on which TPL-001-4 is silent.

Specifically, Part 4.1.4 of Requirement R4 requires the PC to verify that the possible inadvertent operation of the RAS, except for a limited impact RAS, meets the minimum System performance requirements in Table 1 of Reliability Standard TPL-001-4. Instead of referring to TPL-001-4, however, the Requirement lists the System performance requirements that a potential inadvertent operation must satisfy, which account for the performance requirements common to all planning events P0-P7 in TPL-001-4.[51] Similarly, Part 4.1.5 of proposed PRC-012-2 mandates that the PC evaluate whether the RAS, except for limited impact RAS, upon the occurrence of a single component failure, continues to meet "the same performance requirements

[51] Requirement R4, Parts 4.1.4.1 and 4.1.4.5, require the PC to confirm that the BES remains stable and that voltage is within acceptable limits, respectively.

(defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed." Even though Part 4.1.5 exempts limited impact RAS, the standard does not exempt limited impact RAS from meeting each of the performance requirements in TPL-001-4.[52]

Thus, while limited impact RAS are exempt from RC evaluation under Parts 4.1.4 and 4.1.5, these RAS are not exempt from performance requirements in TPL-001-4. The performance requirements under TPL-001-4 and PRC-012-2 are thus designed to support one another and are not mutually exclusive.

iii) Requirement R5

> **R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
>
> **5.1.** Participate in analyzing the RAS operational performance to determine whether:
>
> **5.1.1.** The System events and/or conditions appropriately triggered the RAS.
> **5.1.2.** The RAS responded as designed.
> **5.1.3.** The RAS was effective in mitigating BES performance issues it was designed to address.
> **5.1.4.** The RAS operation resulted in any unintended or adverse BES response.
>
> **5.2.** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).

Pursuant to Requirement R5, RAS-entities must complete a performance analysis of each of its RAS upon the operation or failure to operate of that RAS. This Requirement is necessary for BES integrity and reliability as it verifies that each RAS operation (or misoperation) is consistent with its intended functionality and design. More specifically, the RC and PC reviews

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52 As an example of the coordinated nature of TPL-001-4 and PRC-012-2, the RC may use the analysis completed under the TPL Requirements in its evaluation of whether a RAS qualifies as "limited impact" under Requirements R1, R2, and R3.

performed under Requirements R2 and R4, respectively, RAS are designed to verify the technical integrity of the RAS, not to analyze the operation or misoperation of RAS. An analysis of the actual operation of the RAS according to its design is critical to maintaining the reliability and integrity of the BES. As such, in addition to the reviews required under Requirements R2 and R4, Requirement R5 creates an affirmative obligation for RAS-entities to analyze a RAS after each operation or misoperation. A RAS-entity would be in the best position to review a RAS directly after an event to determine whether the RAS operates correctly and as intended.

Under Requirement R5, each RAS-entity must complete an operational performance analysis after each operation or failure of a RAS to operate to verify that the RAS operated as designed and to identify any deficiencies that occurred during operation, including any adverse effect on the BES. The RAS-entity must analyze RAS performance and provide the details of any deficiencies to the relevant reviewing RC within 120 days of a RAS operation or a failure of the RAS to operate when expected, or on another schedule agreed to by the RC. The 120-day period is consistent with the amount of time required for responsible entities to complete the Protection System Misoperation investigation under Requirements R1, R2, and R3 of Reliability Standard PRC-004-5.

It is important for proposed PRC-012-2 and Commission approved PRC-004-5 to operate contemporaneously, as both standards require the entity responsible for the RAS to perform an analysis when a RAS misoperates. Specifically, Requirements R1, R2, and R3 of Reliability Standard PRC-004-5 focuses on identification, communication and mitigating reoccurrence of a misoperation of a RAS. Requirement R5 of proposed PRC-012-2 focuses on analysis and communication of operation or misoperation of a RAS. Aligning the timeframes for both standards and providing the flexibility for the RAS-entity and RC to agree upon an alternative schedule ensures that, after a RAS misoperation, responsible entities can perform the required analyses on a consistent schedule. Finally, consistent with NERC's Proposal, which requires the RC to maintain continued oversight of each in-service RAS (i.e., the requirements for the RC to review and approve each RAS and for the RC to maintain a database of each RAS in its area) Part 5.2 of Requirement R5 requires the RAS-entity to provide the results of all RAS operational performance analyses that identify deficiencies to its reviewing RC(s).

As the TP may have access to information needed to perform the analysis under Requirement R5,[53] RAS-entities may need to collaborate with their associated TP to verify that the RAS was triggered correctly, responded as designed, and affected the BES as intended. Regardless, the RAS-entity continues to be the responsible entity for purposes of compliance with Requirement R5. RAS-entities with a common RAS (i.e., more than one RAS-entity is responsible for a single RAS) may collaborate to conduct and submit a single, coordinated operational performance analysis.

iv) <u>Requirements R6 and R7</u>

> **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*
>
> - Being notified of a deficiency in its RAS pursuant to Requirement R4, or
> - Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or
> - Identifying a deficiency in its RAS pursuant to Requirement R8.
>
> **R7.** Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

[53] The TP is responsible for developing a long-term reliability plan for the interconnection BES, and information in the reliability plan may be useful to determine whether, according to this plan, the RAS was triggered correctly, responded as designed, and affected the BES as intended. As such, the TP may have useful information for conducting the analysis.

7.1. Implement the CAP.
7.2. Update the CAP if actions or timetables change.
7.3. Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

The reliability objective of Requirements R6 and R7 is to require a RAS-entity to take all necessary steps to address deficiencies associated with its RAS after becoming aware of the deficiency. Under these Requirements, RAS-entities are required to create a CAP to respond to deficiencies with the affected RAS, implement the CAP, update the CAP, and inform the RC of the status of updates and implementation of the CAP.

A RAS-entity may discover deficiencies with its RAS in one of three ways. First, the PC may notify the RAS-entity of an issue with a RAS as a result of its evaluation under Requirement R4. Second, the RAS-entity may discover an issue with its RAS based on its performance analysis after the operation of the RAS or failure of the RAS to operate. Third, the RAS-entity may discover a deficiency with its RAS during its periodic functional test under Requirement R8.

Pursuant to Requirement R6, the RAS-entity must develop a CAP to address any identified deficiency to mitigate potential reliability risks associated with this deficiency. A CAP is defined in the NERC Glossary as "[a] list of actions and an associated timetable for implementation to remedy a specific problem." Accordingly, the RAS-entity must design the CAP to facilitate the corrective measures in the plan by describing all actions necessary to address the deficiency with the RAS and by providing an associated timetable to complete these actions. NERC anticipates that the RAS-entity may design the CAP with information obtained from other parties such as the TP or PC, but the RAS-entity is the entity responsible for compliance with Requirement R6. Depending on the complexity of the identified deficiency(ies), the RAS-entity may need to perform studies or other engineering or consulting work to adequately develop the CAP.

The RAS-entity must develop and submit the CAP to the relevant RC within six months of one of the following: (i) the PC notifies the RAS-entity of the deficiency under Requirement R4, (ii) the RAS-entity notifies the RC of a deficiency under Requirement R5, or (iii) the RAS-entity identifies a deficiency under Requirement R8. NERC designed Requirement R6 as a careful balance between the need for RAS-entity collaboration with other RAS-entities or the relevant TP or PC with the need to address the deficiencies in a reasonable, effective time. Based on this calculation, Requirement R6 specifies a maximum period of six full calendar months for RAS-entity collaboration on the CAP development. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to develop and submit a single, coordinated CAP.

Pursuant to Requirement R7, each RAS-entity must implement the CAP developed according to Requirement R6 (or, more plainly stated, take the actions described in the CAP within the associated timeframe) to address the identified deficiencies. To satisfy its obligations pursuant to Requirements R6 and R7, the RAS entity must develop a CAP designed to mitigate any deficiencies with the RAS in a timely manner. If the RAS-entity makes any change to the actions or schedule in its CAP, the RAS-entity must update the CAP and submit the revised CAP to the RC. In addition, the RAS-entity must notify the RC when the actions under the CAP have been complete and the deficiencies have been addressed. Finally, in the event that the RAS-entity designs a CAP that requires the RAS-entity to make a functional modification to the RAS to address the deficiency, the RAS-entity must resubmit the RAS to the RC for review by submitting information identified in Attachment 1 according to proposed Requirement R1. This is consistent with a RAS-entity's continued obligation under Requirement R1 to obtain RC approval for each "new or functionally modified" RAS.

v) Requirement R8

> **R8.** Each RAS-entity shall participate in performing a functional test of each of its RAS to verify the overall RAS performance and the proper operation of non-Protection System components: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
>
> - At least once every six full calendar years for all RAS not designated as limited impact, or
> - At least once every twelve full calendar years for all RAS designated as limited impact.

In addition to the operational analysis that each RAS-entity must complete after operation or misoperation of a RAS under Requirement R5 of proposed PRC-012-2, the RAS-entity must perform a functional test of its RAS on a periodic basis pursuant to Requirement R8. This functional test serves as additional confirmation that the RAS and the non-Protection System components of the RAS operate as designed.

Responsible entities must test Protection System components that are part of a RAS pursuant to Reliability Standard PRC-005; however, RAS-entities are not required to test the non-protection RAS device (e.g., controller) under any other currently effective Reliability Standard. As each RAS placed in service by a RAS-entity is unique in its operation, location, and design, and role in BES reliability, periodic functional testing of the actual RAS is necessary to maintain reliability across the BES. NERC designed Requirement R8 to require each RAS-entity, as the party with knowledge of the design, installation, and functionality of the RAS, to perform periodic functional testing of each of its RAS to ensure that it continues to operate as designed. A successful functional test that meets the criteria in Requirement R8 to "verify the overall RAS performance and the proper operation of non-Protection System components" would gauge the effectiveness of the device and ensure that the RAS continues to function properly and as designed.

In performing the test, the RAS-entity may test the RAS using an end-to-end testing method or a segmented approach to perform a functional test on all RAS non-protection system components or other components of the RAS not already covered in PRC-005-6. If the RAS-entity employs a segmented approach to testing, the RAS-entity must test each segment of a RAS and may test overlapping segments individually. This individual segment testing, as opposed to testing all segments at the same time, eliminates the need for complex maintenance schedules and outages that may be necessary otherwise. A successful test of one segment only resets the test interval clock for that segment.

Further, when a RAS operates and the RAS-entity performs the analysis under Requirement R5, Part 5.1, the RAS-entity may use the evidence for compliance with Part 5.1 as evidence for compliance with Requirement R8 (i.e., the RAS would be deemed "tested" for purposes of Requirement R8). If one or more segments does not operate, however, the segments that did not operate must be tested within the maximum interval beginning on the date of the previous successful test of the segment(s) that did not operate.

The RAS-entity must perform a functional test for each RAS that is not designed as "limited impact"[54] at least once "every six full calendar years," and for each limited impact RAS at least once "every twelve full calendar years." NERC developed this timeline to ensure that entities have adequate time and resources to acquire and develop the testing framework and to address the potential reliability impacts to the BES created by undiscovered or latent issues that

[54] NERC characterizes a "limited impact RAS" in footnote 1 of proposed PRC-012-2 as a "RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations."

may have an adverse impact on the operation of a RAS. As explained in the Implementation Plan for PRC-012-2 (attached herein as **Exhibit C**), the initial performance obligation for entities responsible for compliance with Requirement R8 must be completed within either six (6) or twelve (12) years after the effective date for PRC-012-2, depending on the type of RAS being tested. This six- and twelve-year timeframe is also consistent with the timeframes for component maintenance requirements related to protection systems, automatic reclosing, and sudden pressure relaying in Table 1-1 of Reliability Standard PRC-005-6.[55]

vi) <u>Requirement R9</u>

> **R9.** Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once every twelve full calendar months. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

Under Requirement R9, each RC is required to create a comprehensive RAS database including all relevant information for each RAS in its RC area and to update this database every twelve months. The RAS database would serve as a tool for the RC to organize necessary RAS data for the needs within its own area and to provide high-level RAS data to relevant entities to identify vulnerabilities and to aid in reliability-related needs across the system.

Requirement R9 obligates the RC to collect information about each RAS in the relevant RC Area identified in Attachment 3. NERC designed Attachment 3 to require the RC to update the minimum information required for the RAS database, including a summary of conditions that trigger a RAS, the corrective actions performed by a RAS, and System issues that are mitigated through corrective action taken by the RAS. The collection of the necessary database

[55] Requirement R1 of PRC-005-6 requires each Transmission Owner, Generator Owner, and Distribution Provider to establish a Protection System Maintenance Program (PSMP) for its Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying based on a schedule consistent with the maintenance intervals specified in Table 1-1 of PRC-005-6. Table 1-1 defines the intervals for maintenance and the types of maintenance activities which must be performed on components with particular attributes.

information is not onerous on the RC, as the data required in Attachment 3 is similar in scope and substance to the information provided to the RC in Attachment 1 pursuant to Requirement R1.

The RC would use the RAS data it collects under Requirement R9 to fulfill its reliability-related responsibilities and to provide other entities with information about each existing RAS that may impact the other entity's operational and planning activities. While the RC may collect more information than just the data nodes requested in Attachment 3, the RC must, at a minimum, update the information in Attachment 3. Again, given its wide-area view and its responsibility to receive relevant information about each RAS before the RAS-entity places the RAS into service, the RC is the appropriate entity to compile RAS-related information specific to each RAS for reliability planning and system analysis across the system.

Operational modeling information is regularly used in the development of NERC powerflow base cases and reliability assessments, and it is provided yearly as required under Reliability Standard MOD-032-1. Thus, consistent with established industry practice, Requirement R9 obligates RCs to update its RAS database with all the information required in Attachment 3 at least once every twelve months to ensure consistency and accuracy of pertinent data. This timeframe provides sufficient time for RAS-entities to provide, and for RCs to collect, all RAS information identified in Attachment 3.

Finally, RCs that do not have an established RAS database upon the effective date of proposed PRC-012-2 would not be able to update information that has not yet been collected and are thus not obligated to "update" the RAS database with the information included in Attachment 3. As described in the Implementation Plan and in *Section IV.C* of this Petition, RCs that have not created a RAS database for collection of pertinent RAS information upon the effective date of proposed Reliability Standard PRC-012-2 are required to create a RAS database by the effective date of PRC-012-2. Upon this initial compliance obligation, the RC would be required to continue to perform the obligation under Requirement R9 every twelve (12) calendar months.

C. Enforceability of Proposed Reliability Standard PRC-012-2

Proposed Reliability Standard PRC-012-2 includes nine Measures to individually support each Requirement, to clarify necessary evidence or actions for compliance, and to help ensure that the Requirements are enforced in a clear, consistent, non-preferential manner, and without prejudice to any party. Each of the nine associated Measures are provided below.

> **M1.** Acceptable evidence may include, but is not limited to, a copy of the Attachment 1 documentation and the dated communications with the reviewing Reliability Coordinator(s) in accordance with Requirement R1.
>
> **M2.** Acceptable evidence may include, but is not limited to, dated reports, checklists, or other documentation detailing the RAS review, and the dated communications with the RAS-entity in accordance with Requirement R2.
>
> **M3.** Acceptable evidence may include, but is not limited to, dated documentation and communications with the reviewing Reliability Coordinator that no reliability issues were identified during the review or that all identified reliability issues were resolved in accordance with Requirement R3.
>
> **M4.** Acceptable evidence may include, but is not limited to, dated reports or other documentation of the analyses comprising the evaluation(s) of each RAS and dated communications with the RAS-entity(ies), Transmission Planner(s), Planning Coordinator(s), and the reviewing Reliability Coordinator(s) in accordance with Requirement R4.
>
> **M5.** Acceptable evidence may include, but is not limited to, dated documentation detailing the results of the RAS operational performance analysis and dated communications with participating RAS-entities and the reviewing Reliability Coordinator(s) in accordance with Requirement R5.
>
> **M6.** Acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each reviewing Reliability Coordinator and each RAS-entity in accordance with Requirement R6.
>
> **M7.** Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders,

maintenance records, and communication with the reviewing Reliability Coordinator(s) that documents the implementation, updating, or completion of a CAP in accordance with Requirement R7.

M8. Acceptable evidence may include, but is not limited to, dated documentation detailing the RAS operational performance analysis for a correct RAS segment or an end-to-end operation (Measure M5 documentation), or dated documentation demonstrating that a functional test of each RAS segment or an end-to-end test was performed in accordance with Requirement R8.

M9. Acceptable evidence may include, but is not limited to, dated spreadsheets, database reports, or other documentation demonstrating a RAS database was updated in accordance with Requirement R9.

Proposed Reliability Standard PRC-012-2 also include VRFs and VSLs for each Requirement. The VSLs and VRFs are part of several elements used to determine an appropriate sanction when the associated Requirement is violated and each comports with the NERC and Commission guidelines relate to their assignment. The VSLs provide guidance on the way that NERC would enforce the Requirements of the proposed Reliability Standards. The VRFs assess the impact to reliability of violating a specific Requirement and represent one of several elements used to determine an appropriate sanction when the associated Requirement is violated.

As further explained in **Exhibit D** of this Petition, seven of the Requirements in proposed Reliability Standard PRC-012-2 have been assigned a "Medium" VRF, while Requirement R8 has been assigned a VRF of "High" and Requirement R9 a VRF of "Lower." Reflective of the nature of the required action, each of the Requirements have been assigned Time Horizons of either "Operational Planning" or "Long-term Planning." As described in **Exhibit D**, the VRFs and VSLs for the proposed Reliability Standard comport with NERC and Commission guidelines.[56]

[56] *See, e.g., N. Am. Elec. Reliability Corp.*, 119 FERC ¶ 61,145, *order on reh'g and compliance filing*, 120 FERC ¶ 61,145 (2007).

D. Proposed Retirements and Withdrawals

In an ongoing effort to consolidate and to remove unnecessary or redundant Requirements or Reliability Standards from its currently effective suite of standards, NERC proposes to retire two currently effective Reliability Standards and withdraw three Reliability Standards that are currently pending with the Commission. As described in the Mapping Document for PRC-012-2, attached herein as **Exhibit E**, proposed PRC-012-2 effectively clarifies and streamlines a variety of existing Requirements applicable to Remedial Action Schemes (formerly known as a "Special Protection System[s]"). As a result of this consolidation, NERC proposes to retire currently effective Reliability Standards PRC-015-1 and PRC-016-1 and withdraw pending "fill-in-the-blank" Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1.[57]

i) <u>Reliability Standard PRC-012-1</u>

In Order No. 693, the Commission did not approve, deny, or remand Reliability Standard PRC-012-1, as the Commission deemed this standard a "fill-in-the-blank" standard. Reliability Standard PRC-012-1, which is the basis for NERC's development of proposed Reliability Standard PRC-012-2, required Regional Entities to create a RAS review process and establish RAS design criteria. As explained in the Mapping Document (**Exhibit E**), all of the Requirements in PRC-012-1 except R2 are now covered in Requirements R1, R2, R3, R4, R5, R6, and R8 of PRC-012-2, as these proposed Requirements obligate the RC, PC, and RAS-entity to create a RAS review process and require the RAS-entity to design corrective measures to correct deficiencies with its respective RAS. Requirement R2 of PRC-012-1 obligated the

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[57] *See* Paragraph 81 Criteria at Exhibit A (proposing to retire standards as "Administrative" if the "Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome."); *see also* Order No. 788.

Regional Reliability Organization to provide its RAS review procedures to other Regional Reliability Organizations and to NERC. In Order No. 693, the Commission did not approve or remand this standard because the standard assigned responsibilities to Regional Reliability Organizations and was "fill-in-the-blank" because it did not properly assign a defined responsibility to a responsible entity.[58] Accordingly, Requirement R2 is administrative in nature and does not contribute to reliability, so NERC did not include the requirement in proposed Reliability Standard PRC-012-2.[59]

Notably, Requirements R1.3 and R1.4 of PRC-012-1 require responsible entities to ensure that failure of a RAS to operate "does not prevent the interconnected transmission system from meeting…TPL-001-0, TPL-002-2, and TPL-003-0" and that an inadvertent operation of the RAS shall "[m]eet 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." As NERC explained in the Mapping Document (**Exhibit E**), the performance obligation in these Requirements would be required under Requirements R1, R2, and R4 of proposed PRC-12-2. As explained in *Section IV.B(ii)(b)* of this petition, while the proposed requirements do not

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[58] NERC developed proposed Reliability Standard PRC-012-2 in consideration of the fact that the Commission neither approved or denied PRC-012-1 and deemed it a "fill-in-the-blank" Reliability Standard. The revised, proposed standard removes the obligation on "Regional Reliability Organizations," and instead places the responsibility on appropriate NERC functional entities.

[59] *See* Paragraph 81 Criteria at Exhibit A. The proposed Reliability Standard does not include a requirement similar to Requirement R2 of PRC-012-1, as this requirement is "administrative" in nature based on the Commission-approved Paragraph 81 Criteria B1. Pursuant to NERC's Paragraph 81 Criteria, a requirement may be retired if it "requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES," and it meets another one of the criteria described in Criteria B of that document. One of those criteria, Criteria B1 (Administrative), states that a Reliability Standard requirement may be retired if it "requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome."[59] Criteria B1 also states that it is "designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program…Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources."

explicitly state that entities must continue to comply with the TPL requirements, responsible entities must continue to comply with these Reliability Standards. Based on the foregoing, NERC proposes to withdraw PRC-012-1 in its entirety.

ii) <u>Reliability Standard PRC-013-1</u>

Similar to Reliability Standard PRC-012-1, the Commission declared that Reliability Standard PRC-13-1 is a "fill-in-the-blank" standard and neither approved, denied, or remanded the standard in Order No. 693.[60] Still, NERC considers the purpose of PRC-013-1, to require responsible entities to maintain a RAS database with pertinent technical information for each RAS, vital to an effective RAS review and maintenance standard. Accordingly, in developing proposed Reliability Standard PRC-012-2, NERC established Requirement R9 to require RCs to maintain a RAS database with specific design information. NERC designed Attachment 3 to support Requirement R9 to ensure that the RAS database includes all relevant technical information about each RAS in its database. The RC must maintain information about each RAS as prescribed in Attachment 3 when creating a RAS database under Requirement R9, as Attachment 3 addresses all information deemed relevant for each RAS in its RAS database. Finally, similar to its treatment of Requirement R2 of Reliability Standard PRC-012-1, NERC declines to include Requirement R2 of PRC-013-1 in proposed PRC-012-2, as it assigns responsibility to a Regional Reliability Organization, establishes a "fill-in-the-blank" standard, and is thus unnecessary. Based on the foregoing, NERC proposes to withdraw PRC-013-1 in its entirety.

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[60] NERC developed proposed Reliability Standard PRC-012-2 in consideration of the fact that the Commission neither approved or denied PRC-013-1 and deemed it a "fill-in-the-blank" Reliability Standard. The revised, proposed standard removes the obligation on "Regional Reliability Organizations," and instead places the responsibility on appropriate NERC functional entities.

iii) Reliability Standard PRC-014-1

In Order No. 693, the Commission neither approved, denied, or remanded Reliability Standard PRC-14-1 and declared that it was a "fill-in-the-blank" standard.[61] However, NERC believes that the performance obligation in PRC-014-1, which required responsible entities to oversee each RAS installed in the respective Regions every five years to ensure that the RAS meets certain criteria and to take correction actions to remediate any RAS that did not meet those criteria, is necessary for an effective RAS program. NERC developed Requirement R4 as a vestige of Reliability Standard PRC-14-1 by requiring the PC to provide oversight of each RAS within the PC area. NERC also developed Requirement R6 based on PRC-014-1 to mandate that each RAS-entity design a CAP to address issues identified in its RAS review. As the obligations under Reliability Standard PRC-014-1 are now covered in Requirements R4 and R6 of proposed PRC-012-2, NERC proposes to withdraw Reliability Standard PRC-014-1.

iv) Reliability Standards PRC-015-1 and PRC-016-1

As the relevant performance requirements in currently effective Reliability Standards PRC-015-1 and PRC-016-1 are subsumed in proposed Reliability Standard PRC-012-2, NERC proposes to retire PRC-015-1 and PRC-016-1.

The purpose of currently effective Reliability Standard PRC-015-1 is "[t]o ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected." The performance obligations of PRC-015-1 require responsible entities to collect data regarding each RAS, review each new or

[61] NERC developed proposed Reliability Standard PRC-012-2 in consideration of the fact that the Commission neither approved or denied PRC-014-1 and deemed it a "fill-in-the-blank" Reliability Standard. The revised standard removes the obligation on "Regional Reliability Organizations," and instead places the responsibility on appropriate NERC functional entities.

functionally modified RAS, and to provide the RAS data to NERC and to Regional Reliability Organizations as necessary. Each of the requirements in PRC-015-1 are vital to ensuring that responsible entities document critical information about each RAS and review each new or functionally modified RAS before placing the RAS into service. Accordingly, NERC has integrated these requirements into Requirements R1, R2, and R3 of proposed Reliability Standard PRC-012-2.

As explained above, these Requirements ensure that (i) each RAS-entity provide specific and detailed information to the relevant RC for review, (ii) each relevant RC review the sufficiency of the RAS design and implementation and provide feedback to the respective RAS-entity, and (iii) each RAS-entity resolves all issues identified by the RC in its RAS review. In Order No. 693, the Commission directed NERC to remove all references to the Regional Reliability Organization as a responsible entity.[62] Also, under proposed Reliability Standard PRC-012-2, the RC reviews each RAS and collects information about each RAS in a RAS database under the proposed Reliability Standard. Requirement R3 of PRC-015-1, which requires responsible entities to provide information about each RAS directly to the Regional Reliability Organization and to NERC, is unnecessary and duplicative and is not included in proposed PRC-012-2.[63]

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[62] Order No. 693 at P 157.

[63] *See* Paragraph 81 Criteria at Exhibit A. The proposed Reliability Standard does not include a requirement similar to Requirement R3 of PRC-015-1, as this requirement is "administrative" in nature based on the Commission-approved Paragraph 81 Criteria B1. Pursuant to NERC's Paragraph 81 Criteria, a requirement may be retired if it "requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES," and it meets another one of the criteria described in Criteria B of that document. One of those criteria, Criteria B1 (Administrative), states that a Reliability Standard requirement may be retired if it "requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome."[63] Criteria B1 also states that it is "designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program…Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources."

Similar to the purpose of Reliability Standard PRC-015-1, the purpose of currently effective Reliability Standard PRC-016-1 is "[t]o ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected." Under this standard, however, responsible entities are required to analyze and record RAS operations, take corrective actions to avoid future misoperations, and provide documentation regarding RAS operation analyses to the relevant Regional Reliability Organizations and NERC as necessary. As these performance requirements are important to establishing an effective and successful RAS program, NERC proposes to move these obligations to Requirements R5, R6, and R7 of proposed Reliability Standard PRC-012-2. Under proposed Requirements R5, R6, and R7, the RAS-entity must analyze RAS operations and provide the results of that analysis to the relevant RC, design a CAP to address any issues identified by the RC, and implement the CAP. The RC, as the entity with the wide-area perspective, is the appropriate entity to oversee RAS, maintain data relevant to operations, use this data to assist responsible entities in operating reliability, and intervene when necessary.

V. <u>EFFECTIVE DATE</u>

NERC respectfully requests that the Commission approve Reliability Standard PRC-012-2 as effective on the first day of the first calendar quarter that is thirty-six (36) months after appropriate governmental approval, pursuant to the respective Implementation Plan included as **Exhibit C** herein. The Implementation Plan provides additional instructions for specific initial performance obligations of certain entities under Requirements R4, R8, and R9 to address any ambiguity that may exist for initial performance obligations related to existing RAS or to RAS designated as "limited impact," and to address responsibilities related to the creation of a RAS database.

The proposed implementation period of thirty-six (36) months for PRC-012-2 is appropriate because the affected RCs may choose to redesign the Regional approval processes currently in existence, which will require considerable time and resources. When establishing a new system for reviewing and approving RAS under proposed PRC-012-2, the RC would be required to develop significant infrastructure, including hiring experts to perform any services that the responsible entities do not currently have available. Entities may desire to continue using existing regional processes to review RAS, but this would still require entities to establish contractual relationships with regional volunteers participating in existing regional processes. Responsible entities would need a thirty-six month implementation period to lay the foundation for an effective, efficient RAS review process to meet obligations under proposed Reliability Standard PRC-012-2.

As written, three of the Requirements, Requirements R4, R8, and R9, are recurring or periodic requirements. As such, the Implementation Plan for PRC-012-2 includes special instructions for the initial implementation of three Requirements. First, Requirement R4 requires the PC to evaluate each RAS every five years. For those RAS that are already in service at the time of implementation and operating as an integrated component of the BES, the Implementation Plan for PRC-012-2, attached herein as **Exhibit C**, explains that the PC must perform the initial performance evaluation of each existing RAS within five (5) years after the effective date of PRC-012-2. In addition, the PC must perform the initial evaluation of each "new or functionally modified RAS" within five (5) years after the date that the reviewing RC approves the RAS.

Second, Requirement R8 requires the RAS-entity to perform a functional test on a periodic basis according to whether the RC has designated the RAS as "limited impact." For added clarity, the Implementation Plan for PRC-012-2 explicitly states that responsible entities must perform the initial functional test of RAS not designated as "limited impact" at least once within six (6) years after the effective date of PRC-012-2 and at least once within twelve (12) years after the effective date if the RAS has been designated as "limited impact."

Finally, certain RCs may not have an established RAS database as anticipated under Requirement R9 and thus may not be able to "update" the database as mandated under that Requirement. The Implementation Plan for PRC-012-2 explains (i) that the initial obligation for RCs without established RAS databases is to establish a database by the effective date of PRC-012-2, and (ii) that the first obligation for all RCs under Requirement R9 must be fulfilled within 12 months of the effective date of PRC-012-2.

VI. <u>CONCLUSION</u>

For the reasons set forth above, NERC respectfully requests that the Commission approve NERC's Proposal regarding (i) proposed Reliability Standard PRC-012-2 in **Exhibit B**; (ii) the Implementation Plan for PRC-012-2 in **Exhibit C;** (iii) the VRFs and VSLs in **Exhibit D;** (iv) retirement of currently effective Reliability Standards PRC-015-1 and PRC-016-1, and (v) withdrawal of Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1.

Respectfully submitted,

/s/ Andrew C. Wills

Charles A. Berardesco
Senior Vice President and General Counsel
Shamai Elstein
Senior Counsel
Andrew C. Wills
Associate Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
charles.berardesco@nerc.net
shamai.elstein@nerc.net
andrew.wills@nerc.net

Counsel for the North American Electric Reliability Corporation

Date: August 5, 2016

Exhibit A

Examples of WECC Local Area Protection Systems (LAPS) and

NPCC Type III Remedial Action Schemes

Exhibit A: Examples of WECC Local Area Protection Systems (LAPS) and NPCC Type III RAS

WECC Local Area Protection Systems[1]

Scheme Name	**Design Objectives** (Contingencies and system conditions for which the scheme was designed)	**Operation** (The actions taken by the scheme in response to Disturbance conditions)	**Modeling** (Information on detection logic or relay settings that control operation of the scheme)
Unit Dropping Scheme	Loss of 345 kV line	Trip generation units to avoid thermal overload of 138 kV line and 230/138 kV transformers	Shed generation for loss of either end of 345 kV line
138 kV Line tripping	Scheme is designed to eliminate overload on the 138 kV line during loss of 345 kV line	Open 138 kV Line during loss of 345 kV line to eliminate overload on the 138 kV line	Transfer trip scheme that will trip the 138 kV line for loss of the 345 kV line
115kV Overload SPS	Prevent overload of 115kV lines in the event of a double line outage of and two 115kV lines.	Opens circuit breaker (CB) 122 and CB 123 which will shed substation load	Open Clear CB 122 and CB 123 if Clear CB 113 and CB 112 are open, and CB 122 and CB 123 are loaded above 215A
Cold	Prevent overload of 500/230kV T1 Transformer	Trips or ramps back generation at Generation Station to prevent overload of the 500/230kV T1 Transformer for a 500 kV single line outage, or a #1 and #2 500kV double line outage.	The RAS actions at Generation Station are as follows: (1) Trip generation to 0 MW level for 500/230kV T1 transformer emergency overload condition and #1 and #2 500kV double line outage. (2) Trip generation to 300 MW level for 500/230kV T1 transformer emergency overload condition and 500kV line outage. (3) Ramp back generation for 500/230kV T1 transformer normal overload condition and 500kV line outage.
Sargent	Thermal overload of the 220 kV Line following N-2 loss of the Units 3 and 4, 220 kV lines	Pre-selected Units 5-8 are tripped to relieve the thermal overload	Line loss logic for the critical line terminals, EMS performs arming calculations every four seconds.
Winter Lake	Loss of 345 kV line with heavy southbound schedule (> ~ 350 MW) on Path XX.	Trip line terminal (#123) for flow > 650 A lasting longer than 8000 cycles	Detect line flow > 650 A with fixed delay of 8000 cycles (2 m 13 s)

[1] The WECC LAPS examples have been redacted to protect Critical Energy Infrastructure Information data and any other Confidential Information.

NPCC Type III Local SPS Examples[2]

Type[3]	Reason for Installation	Initiating Condition	Action Resulting
Generation Rejection	Reclosing Breaker may result in damaging shaft torques on Generator Unit	345 kV Breaker open due to line relaying.	Open Generator Breaker
Transmission Cross Tripping	Prevent low voltage and overloads on the Maine 115 kV system Canadian source contingency with a line out of service	>80 MW reverse power flow on a Maine Autotransformer	Trip the Orrington T1 Autotransformer
Generation Rejection	Overload protection of two underground cables and two overhead lines	Overload of either of two parallel 115 kV lines.	Runback a generating Unit to 150 MW
Generation Rejection	Prevent thermal overload to the remaining line in service	Loss of a 115 kV line with overcurrent on the remaining parallel line	Runback a generating unit to 168 MW
Load Rejection	Prevent overloading a 115 kV line	Loss of Double Circuit Tower Lines	Trip load and disable automatic transfer of load

[2] The NPCC Type III Local SPS examples have been redacted to protect Critical Energy Infrastructure Information data and any other confidential information.

[3] *Note-the majority of Type III SPS (Limited Impact RAS) installed are Generation Rejection schemes installed to alleviate local overloads for specific system conditions and contingencies.

Exhibit B

Proposed Reliability Standard PRC-012-2

A. Introduction

1. **Title:** Remedial Action Schemes
2. **Number:** PRC-012-2
3. **Purpose:** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Planning Coordinator

   4.1.3. RAS-entity – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS

   4.2. Facilities:

   4.2.1. Remedial Action Schemes (RAS)

5. **Effective Date:** See the Implementation Plan for PRC-012-2.

B. Requirements and Measures

R1. Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, a copy of the Attachment 1 documentation and the dated communications with the reviewing Reliability Coordinator(s) in accordance with Requirement R1.

R2. Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated reports, checklists, or other documentation detailing the RAS review, and the dated communications with the RAS-entity in accordance with Requirement R2.

R3. Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Acceptable evidence may include, but is not limited to, dated documentation and communications with the reviewing Reliability Coordinator that no reliability issues were identified during the review or that all identified reliability issues were resolved in accordance with Requirement R3.

R4. Each Planning Coordinator, at least once every five full calendar years, shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Perform an evaluation of each RAS within its planning area to determine whether:

4.1.1. The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed.

4.1.2. The RAS avoids adverse interactions with other RAS, and protection and control systems.

4.1.3. For limited impact[1] RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

4.1.4. Except for limited impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following:

4.1.4.1. The BES shall remain stable.

4.1.4.2. Cascading shall not occur.

4.1.4.3. Applicable Facility Ratings shall not be exceeded.

4.1.4.4. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

4.1.4.5. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

4.1.5. Except for limited impact RAS, 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 is designed.

[1] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

4.2. Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.

M4. Acceptable evidence may include, but is not limited to, dated reports or other documentation of the analyses comprising the evaluation(s) of each RAS and dated communications with the RAS-entity(ies), Transmission Planner(s), Planning Coordinator(s), and the reviewing Reliability Coordinator(s) in accordance with Requirement R4.

R5. Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Participate in analyzing the RAS operational performance to determine whether:

5.1.1. The System events and/or conditions appropriately triggered the RAS.

5.1.2. The RAS responded as designed.

5.1.3. The RAS was effective in mitigating BES performance issues it was designed to address.

5.1.4. The RAS operation resulted in any unintended or adverse BES response.

5.2. Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).

M5. Acceptable evidence may include, but is not limited to, dated documentation detailing the results of the RAS operational performance analysis and dated communications with participating RAS-entities and the reviewing Reliability Coordinator(s) in accordance with Requirement R5.

R6. Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

- Being notified of a deficiency in its RAS pursuant to Requirement R4, or
- Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or
- Identifying a deficiency in its RAS pursuant to Requirement R8.

M6. Acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each reviewing Reliability Coordinator and each RAS-entity in accordance with Requirement R6.

R7. Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

7.1. Implement the CAP.

7.2. Update the CAP if actions or timetables change.

7.3. Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

M7. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, and communication with the reviewing Reliability Coordinator(s) that documents the implementation, updating, or completion of a CAP in accordance with Requirement R7.

R8. Each RAS-entity shall participate in performing a functional test of each of its RAS to verify the overall RAS performance and the proper operation of non-Protection System components: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

- At least once every six full calendar years for all RAS not designated as limited impact, or
- At least once every twelve full calendar years for all RAS designated as limited impact

M8. Acceptable evidence may include, but is not limited to, dated documentation detailing the RAS operational performance analysis for a correct RAS segment or an end-to-end operation (Measure M5 documentation), or dated documentation demonstrating that a functional test of each RAS segment or an end-to-end test was performed in accordance with Requirement R8.

R9. Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once every twelve full calendar months. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M9. Acceptable evidence may include, but is not limited to, dated spreadsheets, database reports, or other documentation demonstrating a RAS database was updated in accordance with Requirement R9.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The RAS-entity (Transmission Owner, Generator Owner, and Distribution Provider) shall each keep data or evidence to show compliance with Requirements R1, R3, R5, R6, R7, and R8, and Measures M1, M3, M5, M6, M7, and M8 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Reliability Coordinator shall each keep data or evidence to show compliance with Requirements R2 and R9, and Measures M2 and M9 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Planning Coordinator shall each keep data or evidence to show compliance with Requirement R4 and Measure M4 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a RAS-entity (Transmission Owner, Generator Owner or Distribution Provider), Reliability Coordinator, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The RAS-entity failed to provide the information identified in Attachment 1 to each Reliability Coordinator prior to placing a new or functionally modified RAS in service or retiring an existing RAS in accordance with Requirement R1.
R2.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90 full calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in accordance with Requirement R2.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	N/A	N/A	N/A	The RAS-entity failed to resolve identified reliability issue(s) to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in service or retiring an existing RAS in accordance with Requirement R3.
R4.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but was late by less than or equal to 30 full calendar days.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate one of the Parts 4.1.1 through 4.1.5.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but was late by more than 90 full calendar days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate two or more of the Parts 4.1.1 through 4.1.5. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to provide the results to one or more of the receiving entities listed in Part 4.2. OR The Planning Coordinator failed to perform the evaluation in accordance with Requirement R4.
R5.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by less than or equal to 10 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address one of the Parts 5.1.1 through 5.1.4.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address two or more of the Parts 5.1.1 through 5.1.4.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to provide the results (Part 5.2) to one or more of the reviewing Reliability Coordinator(s). OR The RAS-entity failed to perform the analysis in accordance with Requirement R5.
R6.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30 full calendar days. OR The RAS-entity developed a Corrective Action Plan but failed to submit it to one or

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				more of its reviewing Reliability Coordinator(s) in accordance with Requirement R6. OR The RAS-entity failed to develop a Corrective Action Plan in accordance with Requirement R6.
R7.	The RAS-entity implemented a CAP in accordance with Requirement R7, Part 7.1, but failed to update the CAP (Part 7.2) if actions or timetables changed, or failed to notify (Part 7.3) each of the reviewing Reliability Coordinator(s) of the updated CAP or completion of the CAP.	N/A	N/A	The RAS-entity failed to implement a CAP in accordance with Requirement R7, Part 7.1.
R8.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by less than	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 30 full calendar days	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 60 full calendar days	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 90 full calendar days.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	or equal to 30 full calendar days.	but less than or equal to 60 full calendar days.	but less than or equal to 90 full calendar days.	OR The RAS-entity failed to perform the functional test for a RAS as specified in Requirement R8.
R9.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90 full calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

D. Regional Variances

None.

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by the Board of Trustees	
0	March 16, 2007	Identified by Commission as “fill-in-the-blank” with no action taken on the standard	
1	November 13, 2014	Adopted by the Board of Trustees	
1	November 19, 2015	Accepted by Commission for informational purposes only	
2	May 5, 2016	Adopted by Board of Trustees	New

Attachment 1
Supporting Documentation for RAS Review

The following checklist identifies important Remedial Action Scheme (RAS) information for each new or functionally modified[2] RAS that the RAS-entity must document and provide to the reviewing Reliability Coordinator(s) (RC). If an item on this list does not apply to a specific RAS, a response of “Not Applicable” for that item is appropriate. When RAS are submitted for functional modification review and approval, only the proposed modifications to that RAS require review; however, the RAS-entity must provide a summary of the existing functionality. The RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS. Additional entities (without decision authority) may be part of the RAS review process at the request of the RC.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.
2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.
3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP.
4. Data to populate the RAS database:
    a. RAS name.
    b. Each RAS-entity and contact information.
    c. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
    d. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
    e. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
    f. Action(s) to be taken by the RAS.
    g. Identification of limited impact[3] RAS.
    h. Any additional explanation relevant to high-level understanding of the RAS.

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[2] Functionally modified: Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

[3] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

II. Functional Description and Transmission Planning Information

1. Contingencies and System conditions that the RAS is intended to remedy.
2. The action(s) to be taken by the RAS in response to disturbance conditions.
3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and the date those technical studies were performed.
4. Information regarding any future System plans that will impact the RAS.
5. RAS-entity proposal and justification for limited impact designation, if applicable.
6. Documentation describing the System performance resulting from the possible inadvertent operation of the RAS, except for limited impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be limited impact must satisfy all of the following:
    a. The BES shall remain stable.
    b. Cascading shall not occur.
    c. Applicable Facility Ratings shall not be exceeded.
    d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.
    e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.
7. An evaluation indicating that the RAS settings and operation avoid adverse interactions with other RAS, and protection and control systems.
8. Identification of other affected RCs.

III. Implementation

1. Documentation describing the applicable equipment used for detection, dc supply, communications, transfer trip, logic processing, control actions, and monitoring.
2. Information on detection logic and settings/parameters that control the operation of the RAS.
3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in service or is being maintained.
4. Documentation describing the System performance resulting from a single component failure in the RAS, except for limited impact RAS, when the RAS is intended to operate. A single component failure in a RAS not determined to be limited impact must 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 is designed. The documentation should describe or illustrate how the design achieves this objective.
5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies RAS information that the RAS-entity shall document and provide to each reviewing RC.

1. Information necessary to ensure that the RC is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of applicable technical studies and technical justifications upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

Attachment 2
Reliability Coordinator RAS Review Checklist

The following checklist identifies reliability-related considerations for the Reliability Coordinator (RC) to review and verify for each new or functionally modified[4] Remedial Action Scheme (RAS). The RC review is not limited to the checklist items and the RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS. If a checklist item is not relevant to a particular RAS, it should be noted as "Not Applicable." If reliability considerations are identified during the review, the considerations and the proposed resolutions should be documented with the remaining applicable Attachment 2 items.

I. Design

1. The RAS actions satisfy performance objectives for the scope of events and conditions that the RAS is intended to mitigate.
2. The designed timing of RAS operation(s) is appropriate to its BES performance objectives.
3. The RAS arming conditions, if applicable, are appropriate to its System performance objectives.
4. The RAS avoids adverse interactions with other RAS, and protection and control systems.
5. The effects of RAS incorrect operation, including inadvertent operation and failure to operate, have been identified.
6. Determination whether or not the RAS is limited impact.[5] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.
7. Except for limited impact RAS as determined by the RC, the possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following:
    a. The BES shall remain stable.
    b. Cascading shall not occur.
    c. Applicable Facility Ratings shall not be exceeded.

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[4] Functionally modified: Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

[5] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

   d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

   e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

8. The effects of future BES modifications on the design and operation of the RAS have been identified, where applicable.

II. Implementation

1. The implementation of RAS logic appropriately correlates desired actions (outputs) with events and conditions (inputs).
2. Except for limited impact RAS as determined by the RC, a single component failure in a RAS does not prevent the BES from meeting the same performance requirements as those required for the events and conditions for which the RAS is designed.
3. The RAS design facilitates periodic testing and maintenance.
4. The mechanism or procedure by which the RAS is armed is clearly described, and is appropriate for reliable arming and operation of the RAS for the conditions and events for which it is designed to operate.

III. RAS Retirement

RAS retirement reviews should assure that there is adequate justification for why a RAS is no longer needed.

Attachment 3
Database Information

1. RAS name.
2. Each RAS-entity and contact information.
3. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
5. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
6. Action(s) to be taken by the RAS.
7. Identification of limited impact[6] RAS.
8. Any additional explanation relevant to high-level understanding of the RAS.

[6] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

Technical Justification

4.1.1 Reliability Coordinator

The Reliability Coordinator (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. The Wide Area purview 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, Planning Coordinator, Transmission Planner, or other entities 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.

4.1.2 Planning Coordinator

The Planning Coordinator (PC) is the best-suited functional entity to perform the RAS evaluation 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, similar to the planning analyses performed by PCs.

4.1.3 RAS-entity

The RAS-entity is any Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If all of the RAS (RAS components) have a single owner, then that RAS-entity has sole responsibility for all the activities assigned within the standard to the RAS-entity. If the RAS (RAS components) have more than one owner, then each separate RAS component owner is a RAS-entity and is obligated to participate in various activities identified by the Requirements.

The standard does not stipulate particular compliance methods. RAS-entities have the option of collaborating to fulfill their responsibilities for each applicable requirement. Such collaboration and coordination may promote efficiency in achieving the reliability objectives of the requirements; however, the individual RAS-entity must be able to demonstrate its participation for compliance. As an example, the individual RAS-entities could collaborate to produce and submit a single, coordinated Attachment 1 to the reviewing RC pursuant to Requirement R1 to initiate the RAS review process.

Limited impact

RAS are unique and customized assemblages of protection and control equipment that vary in complexity and impact on the reliability of the BES. These differences in RAS design, action, and risk to the BES are identified and verified within the construct of Requirements R1-R4 of PRC-012-2.

The reviewing RC has the authority to designate a RAS as limited impact if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. The reviewing RC makes the final determination as to whether a RAS qualifies for the limited impact designation based upon the studies and other information provided with the Attachment 1 submittal by the RAS-entity.

The standard recognizes the Local Area Protection Scheme (LAPS) classification in WECC (Western Electricity Coordinating Council) and the Type III classification in NPCC (Northeast Power Coordinating Council) as initially appropriate for limited impact designation. The following information describing the aforementioned WECC and NPCC RAS is excerpted from the respective regional documentation[7].The drafting team notes that the information below represents the state of the WECC and NPCC regional processes at the time of this standard development and is subject to change before the effective date of PRC-012-2.

WECC: Local Area Protection Scheme (LAPS)
A Remedial Action Scheme (RAS) whose failure to operate would NOT result in any of the following:

- Violations of TPL-001-WECC-RBP System Performance RBP,
- Maximum load loss ≥ 300 MW,
- Maximum generation loss ≥ 1000 MW.

NPCC: Type III
An SPS whose misoperation or failure to operate results in no **significant adverse impact** outside the **local area**.

The following terms are also defined by NPCC to assess the impact of the SPS for classification:

Significant adverse impact – With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from faults or disturbances, shall be deemed as having significant adverse impact:

a. system instability;
b. unacceptable system dynamic response or equipment tripping;
c. voltage levels in violation of applicable emergency limits;
d. loadings on transmission facilities in violation of applicable emergency limits;
e. unacceptable loss of load.

Local area – An electrically confined or radial portion of the system. The geographic size and number of system elements contained will vary based on system characteristics. A local area may be relatively large geographically with relatively few buses in a sparse system, or be

[7] WECC Procedure to Submit a RAS for Assessment Information Required to Assess the Reliability of a RAS Guideline, Revised 10/28/2013 | NPCC Regional Reliability Reference Directory # 7, Special Protection Systems, Version 2, 3/31/2015

relatively small geographically with a relatively large number of buses in a densely networked system.

A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type III in NPCC, is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.

To propose an existing RAS (a RAS implemented prior to the effective date of PRC-012-2) be designated as limited impact by the reviewing RC, the RAS-entity must prepare and submit the appropriate Attachment 1 information that includes the technical justification (evaluations) documenting that the System can meet the performance requirements (specified in Requirement R4, Parts 4.1.4 and 4.1.5) resulting from a single RAS component malfunction or failure, respectively.

There is nothing that precludes a RAS-entity from working with the reviewing RC during the implementation period of PRC-012-2, in anticipation of the standard becoming enforceable. However, even if the reviewing RC determines the RAS qualifies as limited impact, the designation is not relevant until the standard becomes effective. Until then, the existing regional processes remain in effect as well as the existing RAS classifications or lack thereof.

An example of a scheme that could be recognized as a limited impact RAS is a load shedding or generation rejection scheme used to mitigate the overload of a BES transmission line. The inadvertent operation of such a scheme would cause the loss of either a certain amount of generation or load. The evaluation by the RAS-entity should demonstrate that the loss of this amount of generation or load, without the associated contingency for RAS operation actually occurring, is acceptable and not detrimental to the reliability of BES; e.g., in terms of frequency and voltage stability. The failure of that scheme to operate when intended could potentially lead to the overloading of a transmission line beyond its acceptable rating. The RAS-entity would need to demonstrate that this overload, while in excess of the applicable Facility Rating, is not detrimental to the BES outside the contained area (predetermined by studies) affected by the contingency.

Other examples of limited impact RAS include:

- A scheme used to protect BES equipment from damage caused by overvoltage through generation rejection or equipment tripping.
- A centrally-controlled undervoltage load shedding scheme used to protect a contained area (predetermined by studies) of the BES against voltage collapse.
- A scheme used to trip a generating unit following certain BES Contingencies to prevent the unit from going out of synch with the System; where, if the RAS fails to operate and the unit pulls out of synchronism, the resulting apparent impedance swings do not

result in the tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities.

Requirement R1

Each RAS is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES); therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification, or retirement (removal from service) must be completed prior to implementation.

Functional modifications consists of any of the following:

- Changes to System conditions or Contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

An example indicating the limits of an in-kind replacement of a RAS component is the replacement of one relay (or other device) with a relay (or other device) that uses similar functions. For instance, if a RAS included a CO-11 relay which was replaced by an IAC-53 relay, that would be an in-kind replacement. If the CO-11 relay were replaced by a microprocessor SEL-451 relay that used only the same functions as the original CO-11 relay, that would also be an in-kind replacement; however, if the SEL-451 relay was used to add new logic to what the CO-11 relay had provided, then the replacement relay would be a functional modification.

Changes to RAS pickup levels that require no other scheme changes are not considered a functional modification. For example, System conditions require a RAS to be armed when the combined flow on two lines exceeds 500 MW. If a periodic evaluation pursuant to Requirement R4, or other assessment, indicates that the arming level should be reduced to 450 MW without requiring any other RAS changes that would not be a functional modification. Similarly, if a RAS is designed to shed load to reduce loading on a particular line below 1000 amps, then a change in the load shedding trigger from 1000 amps to 1100 amps would not be a functional modification.

Another example illustrates a case where a System change may result in a RAS functional change. Assume that a generation center is connected to a load center through two transmission lines. The lines are not rated to accommodate full plant output if one line is out of service, so a RAS monitors the status of both lines and trips or ramps down the generation to a safe level following loss of either line. Later, one of the lines is tapped to serve additional load. The System that the RAS impacts now includes three lines, loss of any of which is likely to still require generation reduction. The modified RAS will need to monitor all three lines (add two line terminal status inputs to the RAS) and the logic to recognize the specific line outages would change, while the generation reduction (RAS output) requirement may or may not change, depending on which line is out of service. These required RAS changes would be a functional modification.

Any functional modification to a RAS will need to be reviewed and approved through the process described in Requirements R1, R2, and R3. The need for such functional modifications may be identified in several ways including but not limited to the Planning evaluations pursuant to R4, incorrect operations pursuant to R5, a test failure pursuant to R8, or Planning assessments related to future additions or modifications of other facilities.

See Item 4a in the Implementation Section of Attachment 1 in the Supplemental Material section for typical RAS components for which a failure may be considered. The RC has the discretion to make the final determination regarding which components should be regarded as RAS components during its review.

To facilitate a review that promotes reliability, the RAS-entity(ies) must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity(ies) provide them to the reviewing Reliability Coordinator (RC). The RC that coordinates the area where the RAS is located is responsible for the review. In cases where a RAS crosses multiple RC Area boundaries, each affected RC is responsible for conducting either individual reviews or a coordinated review.

Requirement R1 does not specify how far in advance of implementation the RAS-entity(ies) must provide Attachment 1 data to the reviewing RC. The information will need to be submitted early enough to allow RC review in the allotted time pursuant to Requirement R2, including resolution of any reliability issues that might be identified, in order to obtain approval of the reviewing RC. Expeditious submittal of this information is in the interest of each RAS-entity to effect a timely implementation.

Requirement R2

Requirement R2 mandates that the RC perform reviews of all proposed new RAS and existing RAS proposed for functional modification, or retirement (removal from service) in its RC Area.

RAS are unique and customized assemblages of protection and control equipment. As such, they have a potential to introduce reliability risks to the BES, if not carefully planned, designed, and installed. A RAS may be installed to address a reliability issue, or achieve an economic or operational advantage, and could introduce reliability risks that might not be apparent to a RAS-entity(ies). An independent review by a multi-disciplinary panel of subject matter experts with planning, operations, protection, telecommunications, and equipment expertise is an effective means of identifying risks and recommending RAS modifications when necessary.

The RC is the functional entity best suited to perform the RAS reviews because it has the widest area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. This Wide Area purview facilitates the evaluation of interactions among separate RAS as well as interactions among the 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, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC may request assistance in RAS reviews from other parties such as the PC(s) or regional technical groups (e.g., Regional Entities); however, the RC retains responsibility for compliance with the requirement. It is recognized that the RC does not possesses more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not contain compliance requirements. If Reliability Standards address functions that are not described in the model, the Reliability Standard requirements take precedence over the Functional Model. For further reference, please see the Introduction section of NERC’s Reliability Functional Model, Version 5, November 2009. Attachment 2 of this standard is a checklist for assisting the RC in identifying design and implementation aspects of a RAS, and for facilitating consistent reviews of each RAS submitted for review. The time frame of four full calendar months is consistent with current utility practice; however, flexibility is provided by allowing the parties to negotiate a different schedule for the review. Note, an RC may need to include this task in its reliability plan(s) for the NERC Region(s) in which it is located.

Requirement R3

Requirement R3 mandates that each RAS-entity resolve all reliability issues (pertaining to its RAS) identified during the RAS review by the reviewing Reliability Coordinators. Examples of reliability issues include a lack of dependability, security, or coordination. RC approval of a RAS is considered to be obtained when the reviewing RC’s feedback to each RAS-entity indicates that either no reliability issues were identified during the review or all identified reliability issues were resolved to the RC’s satisfaction.

Dependability is a component of reliability that is the measure of certainty of a device to operate when required. If a RAS is installed to meet performance requirements of NERC Reliability Standards, a failure of the RAS to operate when intended would put the System at risk of violating NERC Reliability Standards if specified Contingency(ies) or System conditions occur. This risk is mitigated by designing the RAS so that it will accomplish the intended purpose while experiencing a single RAS component failure. This is often accomplished through redundancy. Other strategies for providing dependability include “over-tripping” load or generation, or alternative automatic backup schemes.

Security is a component of reliability that is the measure of certainty of a device to not operate inadvertently. False or inadvertent operation of a RAS results in taking a programmed action without the appropriate arming conditions, occurrence of specified Contingency(ies), or System conditions expected to trigger the RAS action. Typical RAS actions include shedding load or generation or re-configuring the System. Such actions, if inadvertently taken, are undesirable and may put the System in a less secure state. Worst case impacts from inadvertent operation often occur if all programmed RAS actions occur. If the System performance still satisfies PRC-012-2 Requirement R4, Part 4.3, no additional mitigation is required. Security enhancements to the RAS design, such as voting schemes, are acceptable mitigations against inadvertent operations.

Any reliability issue identified during the review must be resolved before implementing the RAS to avoid placing the System at unacceptable risk. The RAS-entity or the reviewing RC(s) may have alternative ideas or methods available to resolve the issue(s). In either case, the concern needs to be resolved in deference to reliability, and the RC has the final decision.

A specific time period for the RAS-entity to respond to the RC(s) review is not necessary because an expeditious response is in the interest of each RAS-entity to effect a timely implementation.

A specific time period for the RC to respond to the RAS-entity following the RAS review is also not necessary because the RC will be aware of (1) any reliability issues associated with the RAS not being in service and (2) the RAS-entity's schedule to implement the RAS to address those reliability issues. Since the RC is the ultimate arbiter of BES operating reliability, resolving reliability issues is a priority for the RC and serves as an incentive to expeditiously respond to the RAS-entity.

Requirement R4

Requirement R4 mandates that an evaluation of each RAS be performed at least once every five full calendar years. The purpose of a periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that requirements for BES performance following inadvertent RAS operation and single component failure continue to be satisfied. A periodic evaluation is required because changes in System topology or operating conditions may change the effectiveness of a RAS or the way it interacts with and impacts the BES.

A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. Limited impact RAS are not subject to the RAS single component malfunction and failure tests of Parts 4.1.4 and 4.1.5, respectively. Requiring a limited impact RAS to meet these tests would add complexity to the design with minimal benefit to BES reliability.

A RAS implemented after the effective date of this standard can only be designated as limited impact by the reviewing RC(s). A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type III in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.

Requirement R4 also clarifies that the RAS single component failure and inadvertent operation tests do not apply to RAS which are determined to be limited impact. Requiring a limited impact RAS to meet the single component failure and inadvertent operation tests would just add complexity to the design with little or no improvement in the reliability of the BES.

For existing RAS, the initial performance of Requirement R4 must be completed within five full calendar years of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within five full calendar years of the RAS approval date by the reviewing RC(s). Five full calendar years was selected as the maximum time frame between evaluations based on the time frames for similar requirements in Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation can be performed sooner if it is determined that material changes to System topology or System operating conditions could potentially impact the effectiveness or coordination of the RAS. System changes also have the potential to alter the reliability impact of limited impact RAS on the BES. Requirement 4, Part 4.1.3 explicitly requires the periodic evaluation of limited impact RAS to verify the limited impact designation remains applicable. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluations (Requirement R4, Parts 4.1.1 through 4.1.5) are planning analyses that may involve modeling of the interconnected transmission system to assess BES performance. The PC is the functional entity best suited to perform the analyses because they have a wide-area planning perspective. To promote reliability, the PC is required to provide the results of the evaluation to each impacted Transmission Planner and Planning Coordinator, in addition to each reviewing RC and RAS-entity. In cases where a RAS crosses PC boundaries, each affected PC is responsible for conducting either individual evaluations or participating in a coordinated evaluation.

The intent of Requirement R4, Part 4.1.4 is to verify that the possible inadvertent operation of the RAS (other than limited impact RAS), caused by the malfunction of a single component of the RAS, meet the same System performance requirements as those required for the Contingency(ies) or System conditions for which it is designed. If the RAS is designed to meet one of the planning events (P0-P7) in TPL-001-4, the possible inadvertent operation of the RAS must meet the same performance requirements listed in the standard for that planning event. The requirement clarifies that the inadvertent operation to be considered is only that caused by the malfunction of a single RAS component. This allows features to be designed into the RAS to improve security, such that inadvertent operation due to malfunction of a single component is prevented; otherwise, the RAS inadvertent operation must satisfy Requirement R4, Part 4.1.4.

The intent of Requirement R4, Part 4.1.4 is also to verify that the possible inadvertent operation of the RAS (other than limited impact RAS) installed for an extreme event in TPL-001-4 or for some other Contingency or System conditions not defined in TPL-001-4 (therefore without performance requirements), meet the minimum System performance requirements of Category P7 in Table 1 of NERC Reliability Standard TPL-001-4. However, instead of referring to the TPL standard, the requirement lists the System performance requirements that a potential inadvertent operation must satisfy. The performance requirements listed (Requirement R4, Parts 4.1.4.1 – 4.1.4.5) are the ones that are common to all planning events (P0-P7) listed in TPL-001-4.

With reference to Requirement 4, Part 4.1.4, note that the only differences in performance requirements among the TPL (P0-P7) events (not common to all of them) concern Non-Consequential Load Loss and interruption of Firm Transmission Service. It is not necessary for Requirement R4, Part 4.1.4 to specify performance requirements related to these areas because a RAS is only allowed to drop non-consequential load or interrupt Firm Transmission Service if that action is allowed for the Contingency for which it is designed. Therefore, the inadvertent operation should automatically meet Non-Consequential Load Loss or interrupting Firm Transmission Service performance requirements for the Contingency(ies) for which it was designed.

The intent of Requirement R4, Part 4.1.5 is to verify that a single component failure in a RAS, other than limited impact 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 is designed. This analysis is needed to ensure that changing System conditions do not result in the single component failure requirement not being met.

The following is an example of a single component failure causing the System to fail to meet the performance requirements for the P1 event for which the RAS was installed. Consider the instance where a three-phase Fault (P1 event) results in a generating plant becoming unstable (a violation of the System performance requirements of TPL-001-4). To resolve this, a RAS is installed to trip a single generating unit which allows the remaining units at the plant to remain stable. If failure of a single component (e.g., relay) in the RAS results in the RAS failing to operate for the P1 event, the generating plant would become unstable (failing to meet the System performance requirements of TPL-001-4 for a P1 event).

Requirement R4, Part 4.1.5 does not mandate that all RAS have redundant components. For example:

- Consider the instance where a RAS is installed to mitigate an extreme event in TPL-001-4. There are no System performance requirements for extreme events; therefore, the RAS does not need redundancy to meet the same performance requirements as those required for the events and conditions for which the RAS was designed.
- Consider a RAS that arms more load or generation than necessary such that failure of the RAS to drop a portion of load or generation due to that single component failure will still result in satisfactory System performance, as long as tripping the total armed amount of load or generation does not cause other adverse impacts to reliability.

The scope of the periodic evaluation does not include a new review of the physical implementation of the RAS, as this was confirmed by the RC during the initial review and verified by subsequent functional testing. However, it is possible that a RAS design which previously satisfied requirements for inadvertent RAS operation and single component failure by means other than component redundancy may fail to satisfy these requirements at a later time, and must be evaluated with respect to the current System. For example, if the actions of a particular RAS include tripping load, load growth could occur over time that impacts the amount of load to be tripped. These changes could result in tripping too much load upon inadvertent operation and result in violations of Facility Ratings. Alternatively, the RAS might be designed to trip more load than necessary (i.e., “over trip”) in order to satisfy single component failure requirements. System changes could result in too little load being tripped and unacceptable BES performance if one of the loads failed to trip.

Requirement R5

The correct operation of a RAS is important to maintain the reliability and integrity of the BES. Any incorrect operation of a RAS indicates the RAS effectiveness and/or coordination may have been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: (1) verify RAS operation is consistent with implemented design; or (2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120 full calendar day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation; however, flexibility is provided by allowing the parties to negotiate a different schedule for the analysis. To promote reliability, the RAS-entity(s) is required to provide the results of RAS operational performance analyses to its reviewing RC(s) if the analyses revealed a deficiency.

The RAS-entity(ies) may need to collaborate with its associated Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation was triggered correctly (Part 5.1.1), responded as designed (Part 5.1.2), and that the resulting BES response (Parts 5.1.3 and 5.1.4) was consistent with the intended functionality and design of the RAS. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to conduct and submit a single, coordinated operational performance analysis.

Requirement R6

RAS deficiencies potentially pose a reliability risk to the BES. RAS deficiencies may be identified in the periodic RAS evaluation conducted by the PC in Requirement R4, in the operational analysis conducted by the RAS-entity in Requirement R5, or in the functional test performed by the RAS-entity(ies) in Requirement R8. To mitigate potential reliability risks, Requirement R6

mandates that each RAS-entity participate in developing a CAP that establishes the mitigation actions and timetable necessary to address the deficiency.

The RAS-entity(ies) that owns the RAS components, is responsible for the RAS equipment, and is in the best position to develop the timelines and perform the necessary work to correct RAS deficiencies. If necessary, the RAS-entity(ies) may request assistance with development of the CAP from other parties such as its Transmission Planner or Planning Coordinator; however, the RAS-entity has the responsibility for compliance with this requirement.

A CAP may require functional changes be made to a RAS. In this case, Attachment 1 information must be submitted to the reviewing RC(s), an RC review must be performed to obtain RC approval before the RAS-entity can place RAS modifications in service, per Requirements R1, R2, and R3.

Depending on the complexity of the issues, development of a CAP may require study, engineering or consulting work. A timeframe of six full calendar months is allotted to allow enough time for RAS-entity collaboration on the CAP development, while ensuring that deficiencies are addressed in a reasonable time. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to develop and submit a single, coordinated CAP. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the RAS deficiency is resolved. The possibility of such operating restrictions will incent the RAS-entity to resolve the issue as quickly as possible.

The following are example situations of when a CAP is required:

- A determination after a RAS operation/non-operation investigation that the RAS did not meet performance expectations or did not operate as designed.
- Periodic planning assessment reveals RAS changes are necessary to correct performance or coordination issues.
- Equipment failures.
- Functional testing identifies that a RAS is not operating as designed.

Requirement R7

Requirement R7 mandates that each RAS-entity implement its CAP developed in Requirement R6 which mitigates the deficiencies identified in Requirements R4, R5, or R8. By definition, a CAP is: “A list of actions and an associated timetable for implementation to remedy a specific problem.”

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. If the CAP is changed, the RAS-entity must notify the reviewing Reliability

Coordinator(s). The RAS-entity must also notify the Reliability Coordinator(s) when the CAP has been completed.

The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions will incent the RAS-entity to complete the CAP as quickly as possible.

Requirement R8

The reliability objective of Requirement R8 is to test the non-Protection System components of a RAS (controllers such as programmable logic controllers (PLCs)) and to verify the overall performance of the RAS through functional testing. Functional tests validate RAS operation by ensuring System states are detected and processed, and that actions taken by the controls are correct and occur within the expected time using the in-service settings and logic. Functional testing is aimed at assuring overall RAS performance and not the component focused testing contained in the PRC-005 maintenance standard.

Since the functional test operates the RAS under controlled conditions with known System states and expected results, testing and analysis can be performed with minimum impact to the BES and should align with expected results. The RAS-entity is in the best position to determine the testing procedure and schedule due to their overall knowledge of the RAS design, installation, and functionality. Periodic testing provides the RAS-entity assurance that latent failures may be identified and also promotes identification of changes in the System that may have introduced latent failures.

The six and twelve full calendar year functional testing intervals are greater than the annual or bi-annual periodic testing performed in some NERC Regions. However, these intervals are a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS. Longer test intervals for limited impact RAS are acceptable because incorrect operations or failures to operate present a low reliability risk to the Bulk Power System.

Functional testing is not synonymous with end-to-end testing. End-to-end testing is an acceptable method but may not be feasible for many RAS. When end-to-end testing is not possible, a RAS-entity may use a segmented functional testing approach. The segments can be tested individually negating the need for complex maintenance schedules. In addition, actual RAS operation(s) can be used to fulfill the functional testing requirement. If a RAS does not operate in its entirety during a System event or System conditions do not allow an end-to-end scheme test, then the segmented approach should be used to fulfill this Requirement. Functional testing includes the testing of all RAS inputs used for detection, arming, operating, and data collection. Functional testing, by default operates the processing logic and infrastructure of a RAS, but focuses on the RAS inputs as well as the actions initiated by RAS outputs to address the System condition(s) for which the RAS is designed. All segments and components of a RAS must be tested or have proven operations within the applicable maximum test interval to demonstrate compliance with the Requirement.

As an example of segment testing, consider a RAS controller implemented using a PLC that receives System data, such as loading or line status, from distributed devices. These distributed devices could include meters, protective relays, or other PLCs. In this example RAS, a line protective relay is used to provide an analog metering quantity to the RAS control PLC. A functional test would verify that the System data is received from the protective relay by the PLC, processed by the PLC, and that PLC outputs are appropriate. There is no need to verify the protective relay's ability to measure the power system quantities, as this is a requirement for Protection Systems used as RAS in PRC-005, Table 1-1, Component Type – Protective Relay. Rather the functional test is focused on the use of the protective relay data at the PLC, including the communications data path from relay to PLC if this data is essential for proper RAS operation. Additionally, if the control signal back to the protective relay is also critical to the proper functioning of this example RAS, then that path is also verified up to the protective relay. This example describes a test for one segment of a RAS which verifies RAS action, verifies PLC control logic, and verifies RAS communications.

IEEE C37.233, "IEEE Guide for Power System Protection Testing," 2009 section 8 (particularly 8.3-8.5), provides an overview of functional testing. The following opens section 8.3:

> Proper implementation requires a well-defined and coordinated test plan for performance evaluation of the overall system during agreed maintenance intervals. The maintenance test plan, also referred to as functional system testing, should include inputs, outputs, communication, logic, and throughput timing tests. The functional tests are generally not component-level testing, rather overall system testing. Some of the input tests may need to be done ahead of overall system testing to the extent that the tests affect the overall performance. The test coordinator or coordinators need to have full knowledge of the intent of the scheme, isolation points, simulation scenarios, and restoration to normal procedures.
>
> The concept is to validate the overall performance of the scheme, including the logic where applicable, to validate the overall throughput times against system modeling for different types of Contingencies, and to verify scheme performance as well as the inputs and outputs.

If a RAS passes a functional test, it is not necessary to provide that specific information to the RC because that is the expected result and requires no further action. If a segment of a RAS fails a functional test, the status of that degraded RAS is required to be reported (in Real-time) to the Transmission Operator via PRC-001, Requirement R6, then to the RC via TOP-001-3, Requirement R8. See Phase 2 of Project 2007-06 for the mapping document from PRC-001 to other standards regarding notification of RC by TOP if a deficiency is found during testing. Consequently, it is not necessary to include a similar requirement in this standard.

The initial test interval begins on the effective date of the standard pursuant to the implementation plan. Subsequently, the maximum allowable interval between functional tests is six full calendar years for RAS that are not designated as limited impact RAS and twelve full calendar years for RAS that are designated as limited impact RAS. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. A RAS-entity may choose to count a correct RAS operation as a qualifying functional test for those RAS segments which operate. If a System event causes a correct, but partial RAS operation, separate functional tests of the segments that did not operate are still required within the maximum test interval that started on the date of the previous successful test of those (non-operating) segments in order to be compliant with Requirement R8.

Requirement R9

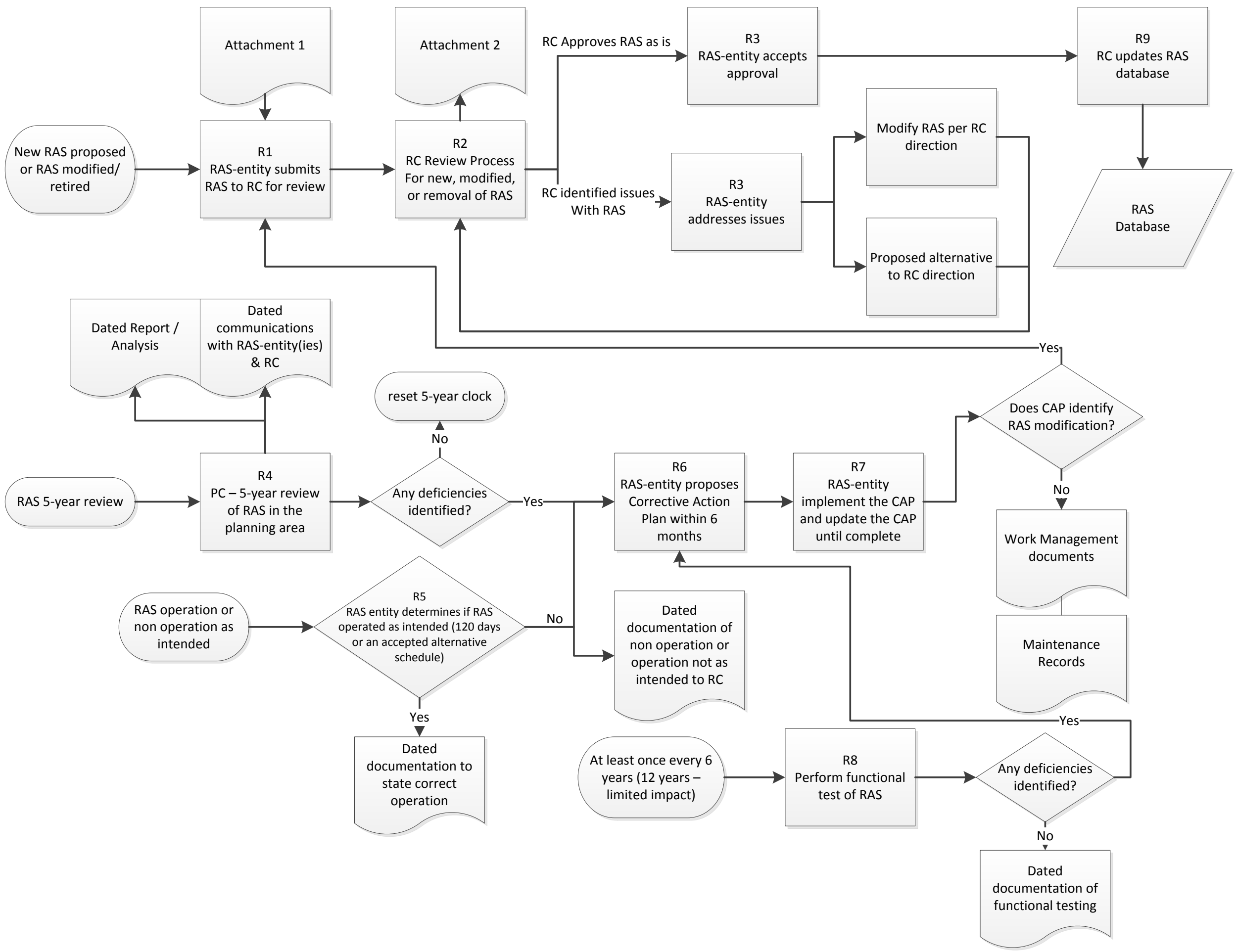
The RAS database required to be maintained by the RC in Requirement R9 ensures information regarding existing RAS is available. Attachment 3 contains the minimum information that is required to be included about each RAS listed in the database. Additional information can be requested by the RC.

The database enables the RC to provide other entities high-level information on existing RAS that could potentially impact the operational and/or planning activities of that entity. The information provided is sufficient for an entity with a reliability need to evaluate whether the RAS can impact its System. For example, a RAS performing generation rejection to mitigate an overload on a transmission line may cause a power flow change within an adjacent entity area. This entity should be able to evaluate the risk that a RAS poses to its System from the high-level information provided in the RAS database.

The RAS database does not need to list detailed settings or modeling information, but the description of the System performance issues, System conditions, and the intended corrective actions must be included. If additional details about the RAS operation are required, the entity may obtain the contact information of the RAS-entity from the RC.

Process Flow Diagram

The diagram below depicts the process flow of the PRC-012-2 requirements.



Technical Justifications for Attachment 1 Content
Supporting Documentation for RAS Review

To perform an adequate review of the expected reliability implications of a Remedial Action Scheme (RAS), it is necessary for the RAS-entity(ies) to provide a detailed list of information describing the RAS to the reviewing RC. If there are multiple RAS-entities for a single RAS, information will be needed from all RAS-entities. Ideally, in such cases, a single RAS-entity will take the lead to compile all the data identified into a single Attachment 1.

The necessary data ranges from a general overview of the RAS to summarized results of transmission planning studies, to information about hardware used to implement the RAS. Coordination between the RAS and other RAS and protection and control systems will be examined for possible adverse interactions. This review can include wide-ranging electrical design issues involving the specific hardware, logic, telecommunications, and other relevant equipment and controls that make up the RAS.

Attachment 1

The following checklist identifies important RAS information for each new or functionally modified[8] RAS that the RAS-entity shall document and provide to the RC for review pursuant to Requirement R1. When a RAS has been previously reviewed, only the proposed modifications to that RAS require review; however, it will be helpful to each reviewing RC if the RAS-entity provides a summary of the existing RAS functionality.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.

   Provide a description of the RAS to give an overall understanding of the functionality and a map showing the location of the RAS. Identify other protection and control systems requiring coordination with the RAS. See RAS Design below for additional information.

   Provide a single-line drawing(s) showing all sites involved. The drawing(s) should provide sufficient information to allow the RC review team to assess design reliability, and should include information such as the bus arrangement, circuit breakers, the associated switches, etc. For each site, indicate whether detection, logic, action, or a combination of these is present.

2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.

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[8] Functionally modified: Any modification to a RAS consisting of any of the following:

- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP. [Reference NERC Reliability Standard PRC-012-2, Requirements R5 and R7]

   Provide a description of any functional modifications to a RAS that are part of a CAP that are proposed to address performance deficiency(ies) identified in the periodic evaluation pursuant to Requirement R4, the analysis of an actual RAS operation pursuant to Requirement R5, or functional test failure pursuant to Requirement R8. A copy of the most recent CAP must be submitted in addition to the other data specified in Attachment 1.

4. Initial data to populate the RAS database.

   a. RAS name.

   b. Each RAS-entity and contact information.

   c. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent five full calendar year (Requirement R4) evaluation date; and, date of retirement, if applicable.

   d. System performance issue or reason for installing the RAS (*e.g.*, thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery).

   e. Description of the Contingencies or System conditions for which the RAS was designed (initiating conditions).

   f. Corrective action taken by the RAS.

   g. Identification of limited impact[9] RAS.

   h. Any additional explanation relevant to high level understanding of the RAS.

   Note: This is the same information as is identified in Attachment 3. Supplying the data at this point in the review process ensures a more complete review and minimizes any administrative burden on the reviewing RC(s).

II. Functional Description and Transmission Planning Information

1. Contingencies and System conditions that the RAS is intended to remedy. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.1]

   a. The System conditions that would result if no RAS action occurred should be identified.

   b. Include a description of the System conditions that should arm the RAS so as to be ready to take action upon subsequent occurrence of the critical System Contingencies or other operating conditions when RAS action is intended to occur. If no arming conditions are required, this should also be stated.

[9] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

   c. Event-based RAS are triggered by specific Contingencies that initiate mitigating action. Condition-based RAS may also be initiated by specific Contingencies, but specific Contingencies are not always required. These triggering Contingencies and/or conditions should be identified.

2. The actions to be taken by the RAS in response to disturbance conditions. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.2]

   Mitigating actions are designed to result in acceptable System performance. These actions should be identified, including any time constraints and/or "backup" mitigating measures that may be required in case of a single RAS component failure.

3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and the date those technical studies were performed. [Reference NEC Reliability Standard PRC-014, R3.2]

   Review the scheme purpose and impact to ensure it is (still) necessary, serves the intended purposes, and meets current performance requirements. While copies of the full, detailed studies may not be necessary, any abbreviated descriptions of the studies must be detailed enough to allow the reviewing RC(s) to be convinced of the need for the scheme and the results of RAS-related operations.

4. Information regarding any future System plans that will impact the RAS. [Reference NERC Reliability Standard PRC-014, R3.2]

   The RC's other responsibilities under the NERC Reliability Standards focus on the Operating Horizon, rather than the Planning Horizon. As such, the RC is less likely to be aware of any longer range plans that may have an impact on the proposed RAS. Such knowledge of future Plans is helpful to provide perspective on the capabilities of the RAS.

5. RAS-entity proposal and justification for limited impact designation, if applicable.

   A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type 3 in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.

6. Documentation describing the System performance resulting from the possible inadvertent operation of the RAS, except for limited impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be limited impact must satisfy all of the following: [Reference NERC Reliability Standard PRC-012, R1.4]

a. The BES shall remain stable.

b. Cascading shall not occur.

c. Applicable Facility Ratings shall not be exceeded.

d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

7. An evaluation indicating that the RAS settings and operation avoids adverse interactions with other RAS, and protection and control systems.
[Reference NERC Reliability Standards PRC-012, R1.5 and PRC-014, R3.4]

   RAS are complex schemes that may take action such as tripping load or generation or re-configuring the System. Many RAS depend on sensing specific System configurations to determine whether they need to arm or take actions. An examples of an adverse interaction: A RAS that reconfigures the System also changes the available Fault duty, which can affect distance relay overcurrent (“fault detector”) supervision and ground overcurrent protection coordination.

8. Identification of other affected RCs.

   This information is needed to aid in information exchange among all affected entities and coordination of the RAS with other RAS and protection and control systems.

III. Implementation

1. Documentation describing the applicable equipment used for detection, dc supply, communications, transfer trip, logic processing, control actions, and monitoring.

   Detection
   Detection and initiating devices, whether for arming or triggering action, should be designed to be secure. Several types of devices have been commonly used as disturbance, condition, or status detectors:

   - Line open status (event detectors),
   - Protective relay inputs and outputs (event and parameter detectors),
   - Transducer and IED (analog) inputs (parameter and response detectors),
   - Rate of change (parameter and response detectors).

   DC Supply
   Batteries and charges, or other forms of dc supply for RAS, are commonly also used for Protection Systems. This is acceptable, and maintenance of such supplies is covered by PRC-005. However, redundant RAS, when used, should be supplied from separately protected (fused or breakered) circuits.

Communications: Telecommunications Channels

Telecommunications channels used for sending and receiving RAS information between sites and/or transfer trip devices should meet at least the same criteria as other relaying protection communication channels. Discuss performance of any non-deterministic communication systems used (such as Ethernet).

The scheme logic should be designed so that loss of the channel, noise, or other channel or equipment failure will not result in a false operation of the scheme.

It is highly desirable that the channel equipment and communications media (power line carrier, microwave, optical fiber, etc.) be owned and maintained by the RAS-entity, or perhaps leased from another entity familiar with the necessary reliability requirements. All channel equipment should be monitored and alarmed to the dispatch center so that timely diagnostic and repair action shall take place upon failure. Publicly switched telephone networks are generally an undesirable option.

Communication channels should be well labeled or identified so that the personnel working on the channel can readily identify the proper circuit. Channels between entities should be identified with a common name at all terminals.

Transfer Trip

Transfer trip equipment, when separate from other RAS equipment, should be monitored and labeled similarly to the channel equipment.

Logic Processing

All RAS require some form of logic processing to determine the action to take when the scheme is triggered. Required actions are always scheme dependent. Different actions may be required at different arming levels or for different Contingencies. Scheme logic may be achievable by something as simple as wiring a few auxiliary relay contacts or by much more complex logic processing.

Platforms that have been used reliably and successfully include PLCs in various forms, personal computers (PCs), microprocessor protective relays, remote terminal units (RTUs), and logic processors. Single-function relays have been used historically to implement RAS, but this approach is now less common except for very simple new RAS or minor additions to existing RAS.

Control Actions

RAS action devices may include a variety of equipment such as transfer trip, protective relays, and other control devices. These devices receive commands from the logic processing function (perhaps through telecommunication facilities) and initiate RAS actions at the sites where action is required.

Monitoring by SCADA/EMS should include at least

- Whether the scheme is in service or out of service.
    - For RAS that are armed manually, the arming status may be the same as whether the RAS is in service or out of service.

  - For RAS that are armed automatically, these two states are independent because a RAS that has been placed in service may be armed or unarmed based on whether the automatic arming criteria have been met.

- The current operational state of the scheme (available or not).
- In cases where the RAS requires single component failure performance; e.g., redundancy, the minimal status indications should be provided separately for each RAS.
  - The minimum status is generally sufficient for operational purposes; however, where possible it is often useful to provide additional information regarding partial failures or the status of critical components to allow the RAS-entity to more efficiently troubleshoot a reported failure. Whether this capability exists will depend in part on the design and vintage of equipment used in the RAS. While all schemes should provide the minimum level of monitoring, new schemes should be designed with the objective of providing monitoring at least similar to what is provided for microprocessor-based Protection Systems.

2. Information on detection logic and settings/parameters that control the operation of the RAS. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.3]

   Several methods to determine line or other equipment status are in common use, often in combination:

   a. Auxiliary switch contacts from circuit breakers and disconnect switches (52a/b, 89a/b)—the most common status monitor; “a” contacts exactly emulate actual breaker status, while “b” contacts are opposite to the status of the breaker;
   b. Undercurrent detection—a low level indicates an open condition, including at the far end of a line; pickup is typically slightly above the total line-charging current;
   c. Breaker trip coil current monitoring—typically used when high-speed RAS response is required, but usually in combination with auxiliary switch contacts and/or other detection because the trip coil current ceases when the breaker opens; and
   d. Other detectors such as angle, voltage, power, frequency, rate of change of the aforementioned, out of step, etc. are dependent on specific scheme requirements, but some forms may substitute for or enhance other monitoring described in items ‘a’, ‘b’, and ‘c’ above.

   Both RAS arming and action triggers often require monitoring of analog quantities such as power, current, and voltage at one or more locations and are set to detect a specific level of the pertinent quantity. These monitors may be relays, meters, transducers, or other devices

3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in service or is being maintained.

In this context, a multifunction device (e.g., microprocessor-based relay) is a single component that is used to perform the function of a RAS in addition to protective relaying and/or SCADA simultaneously. It is important that other applications in the multifunction device do not compromise the functionality of the RAS when the device is in service or when it is being maintained. The following list outlines considerations when the RAS function is applied in the same microprocessor-based relay as equipment protection functions:

a. Describe how the multifunction device is applied in the RAS.

b. Show the general arrangement and describe how the multi-function device is labeled in the design and application, so as to identify the RAS and other device functions.

c. Describe the procedures used to isolate the RAS function from other functions in the device.

d. Describe the procedures used when each multifunction device is removed from service and whether coordination with other protection schemes is required.

e. Describe how each multifunction device is tested, both for commissioning and during periodic maintenance testing, with regard to each function of the device.

f. Describe how overall periodic RAS functional and throughput tests are performed if multifunction devices are used for both local protection and RAS.

g. Describe how upgrades to the multifunction device, such as firmware upgrades, are accomplished. How is the RAS function taken into consideration?

Other devices that are usually not considered multifunction devices such as auxiliary relays, control switches, and instrument transformers may serve multiple purposes such as protection and RAS. Similar concerns apply for these applications as noted above.

4. Documentation describing the System performance resulting from a single component failure in the RAS, except for limited impact RAS, when the RAS is intended to operate. A single component failure in a RAS not determined to be limited impact must 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 is designed. The documentation should describe or illustrate how the design achieves this objective. [Reference NERC Reliability Standard PRC-012, R1.3]

   RAS automatic arming, if applicable, is vital to RAS and System performance and is therefore included in this requirement.

   Acceptable methods to achieve this objective include, but are not limited to the following:

   a. Providing redundancy of RAS components. Typical examples are listed below:

      i. Protective or auxiliary relays used by the RAS.

ii. Communications systems necessary for correct operation of the RAS.

iii. Sensing devices used to measure electrical or other quantities used by the RAS.

iv. Station dc supply associated with RAS functions.

v. Control circuitry associated with RAS functions through the trip coil(s) of the circuit breakers or other interrupting devices.

vi. Logic processing devices that accept System inputs from RAS components or other sources, make decisions based on those inputs, or initiate output signals to take remedial actions.

b. Arming more load or generation than necessary such that failure of the RAS to drop a portion of load or generation due to that single component failure will still result in satisfactory System performance, as long as tripping the total armed amount of load or generation does not cause other adverse impacts to reliability.

c. Using alternative automatic actions to back up failures of single RAS components.

d. 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.

5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies important RAS information for each existing RAS to be retired that the RAS-entity shall document and provide to the Reliability Coordinator for review pursuant to Requirement R1.

1. Information necessary to ensure that the Reliability Coordinator is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of technical studies and technical justifications, if applicable, upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

While the documentation necessary to evaluate RAS removals is not as extensive as for new or functionally modified RAS, it is still vital that, when the RAS is no longer available, System performance will still meet the appropriate (usually TPL) requirements for the Contingencies or System conditions that the RAS had been installed to remediate.

Technical Justification for Attachment 2 Content

Reliability Coordinator RAS Review Checklist

Attachment 2 is a checklist provided to facilitate consistent reviews continent-wide for new or functionally modified RAS prior to the RAS installation. The checklist is meant to assist the RC in identifying reliability-related considerations relevant to various aspects of RAS design and implementation.

Technical Justifications for Attachment 3 Content

Database Information

Attachment 3 contains the minimum information that the RC must consolidate into its database for each RAS in its area.

1. RAS name.
    - The name used to identify the RAS.
2. Each RAS-entity and contact information.
    - A reliable phone number or email address should be included to contact each RAS-entity if more information is needed.
3. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent five full calendar year (Requirement R4) evaluation date; and, date of retirement, if applicable.
    - Specify each applicable date.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery).
    - A short description of the reason for installing the RAS is sufficient, as long as the main System issues addressed by the RAS can be identified by someone with a reliability need.
5. Description of the Contingencies or System conditions for which the RAS was designed (initiating conditions).
    - A high level summary of the conditions/Contingencies is expected. Not all combinations of conditions are required to be listed.
6. Corrective action taken by the RAS.
    - A short description of the actions should be given. For schemes shedding load or generation, the maximum amount of megawatts should be included.

7. Identification of limited impact[10] RAS.
    - Specify whether or not the RAS is designated as limited impact.
8. Any additional explanation relevant to high-level understanding of the RAS.
    - If deemed necessary, any additional information can be included in this section, but is not mandatory.

[10] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

Rationale

Rationale for Requirement R1: Each Remedial Action Scheme (RAS) is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES). Therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification or retirement; i.e., removal from service must be completed prior to implementation or retirement.

Functional modifications consist of any of the following:

- Changes to System conditions or Contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

To facilitate a review that promotes reliability, the RAS-entity must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity provide them to the reviewing Reliability Coordinator (RC). The RC (reviewing RC) that coordinates the area where the RAS is located is responsible for the review. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate and submit a single, coordinated Attachment 1 to the reviewing RC. In cases where a RAS crosses RC Area boundaries, each affected RC is responsible for conducting either individual reviews or participating in a coordinated review.

Rationale for Requirement R2: The RC is the functional entity best suited to perform the RAS review because it has the widest area operational and reliability perspective of all functional entities and an awareness of reliability issues in any neighboring RC Area. This Wide Area purview facilitates the evaluation of interactions among separate RAS as well as interactions among RAS and other protection and control systems. Review by the RC also minimizes the possibility of a conflict of interest that could exist because of business relationships among the RAS-entity, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC is not expected to possess more information or ability than anticipated by their functional registration as designated by NERC. The RC may request assistance to perform RAS reviews from other parties such as the PC or regional technical groups; however, the RC will retain the responsibility for compliance with this requirement.

Attachment 2 of this standard is a checklist the RC can use to identify design and implementation aspects of RAS and facilitate consistent reviews for each submitted RAS. The time frame of four full calendar months is consistent with current utility and regional practice;

however, flexibility is provided by allowing the RC(s) and RAS-entity(ies) to negotiate a mutually agreed upon schedule for the review.

Note: An RC may need to include this task in its reliability plan(s) for the NERC Regions(s) in which it is located.

Rationale for Requirement R3: The RC review is intended to identify reliability issues that must be resolved before the RAS can be put in service. Examples of reliability issues include a lack of dependability, security, or coordination.

A specific time period for the RAS-entity to respond to the reviewing RC following identification of any reliability issue(s) is not necessary because the RAS-entity wants to expedite the timely approval and subsequent implementation of the RAS.

A specific time period for the RC to respond to the RAS-entity following the RAS review is also not necessary because the RC will be aware of (1) any reliability issues associated with the RAS not being in service and (2) the RAS-entity's schedule to implement the RAS to address those reliability issues. Since the RC is the ultimate arbiter of BES operating reliability, resolving reliability issues is a priority for the RC and serves as an incentive to expeditiously respond to the RAS-entity.

Rationale for Requirement R4: Requirement R4 mandates that an evaluation of each RAS be performed at least once every five full calendar years. The purpose of the periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that, if a RAS single component malfunction or single component failure were to occur, the requirements for BES performance would continue to be satisfied. A periodic evaluation is required because changes in System topology or operating conditions may change the effectiveness of a RAS or the way it impacts the BES.

RAS are unique and customized assemblages of protection and control equipment that vary in complexity and impact on the reliability of the BES. In recognition of these differences, RAS can be designated by the reviewing RC(s) as limited impact. A limited impact RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. The "BES" qualifier in the preceding statement modifies all of the conditions that follow it. Limited impact RAS are not subject to the RAS single component malfunction and failure tests of Parts 4.1.4 and 4.1.5, respectively. Requiring a limited impact RAS to meet these tests would add complexity to the design with minimal benefit to BES reliability. See the Supplemental Material for more on the limited impact designation.

The standard recognizes the Local Area Protection Scheme (LAPS) classification in WECC (Western Electricity Coordinating Council) and the Type III classification in NPCC (Northeast Power Coordinating Council) as initially appropriate for limited impact designation. A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type III in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.

For existing RAS, the initial performance of Requirement R4 must be completed within five full calendar years of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within five full calendar years of the RAS approval date by the reviewing RC(s). Five full calendar years was selected as the maximum time frame between evaluations based on the time frames for similar requirements in Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation can be performed sooner if it is determined that material changes to System topology or System operating conditions could potentially impact the effectiveness or coordination of the RAS. System changes also have the potential to alter the reliability impact of limited impact RAS on the BES. Requirement 4, Part 4.1.3 explicitly requires the periodic evaluation of limited impact RAS to verify the limited impact designation remains applicable; the PC can use its discretion as to how this evaluation is performed. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluations (Requirement R4, Parts 4.1.1 through 4.1.5) are planning analyses that may involve modeling of the interconnected transmission system to assess BES performance. The Planning Coordinator (PC) is the functional entity best suited to perform this evaluation because they have a wide area planning perspective. To promote reliability, the PC is required to provide the results of the evaluation to each impacted Transmission Planner and Planning Coordinator, in addition to each reviewing RC and RAS-entity. In cases where a RAS crosses PC boundaries, each affected PC is responsible for conducting either individual evaluations or participating in a coordinated evaluation.

The previous version of this standard (PRC-012-1 Requirement 1, R1.4) states "… 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." Requirement R4 clarifies that the inadvertent operation to be considered would only be that caused by the malfunction of a single RAS component. This allows security features to be designed into the RAS such that inadvertent operation due to a single component malfunction is prevented. Otherwise, consistent with PRC-012-1 Requirement 1, R1.4, the RAS should be designed so that its whole or partial inadvertent operation due to a single component malfunction satisfies the System 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 some other Contingency or System condition not defined in TPL-001-4 (therefore without performance requirements), its inadvertent operation still must meet some minimum System performance requirements. However, instead of referring to the TPL-001-4, Requirement R4 lists the System performance requirements that the inadvertent operation must satisfy. The performance requirements listed (Parts 4.1.4.1 – 4.1.4.5) are the ones that are common to all planning events P0-P7 listed in TPL-001-4.

Rationale for Requirement R5: The correct operation of a RAS is important for maintaining the reliability and integrity of the BES. Any incorrect operation of a RAS indicates that the RAS effectiveness and/or coordination has been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: 1) verify RAS operation was consistent with the implemented design; or 2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120 full calendar day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation. To promote reliability, each RAS-entity is required to provide the results of RAS operational performance analyses that identified any deficiencies to its reviewing RC(s).

RAS-entities may need to collaborate with their associated Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation was triggered correctly (Part 5.1.1), responded as designed (Part 5.1.2), and that the resulting BES response (Parts 5.1.3 and 5.1.4) was consistent with the intended functionality and design of the RAS. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to conduct and submit a single, coordinated operational performance analysis.

Rationale for Requirement R6: Deficiencies identified in the periodic RAS evaluation conducted by the PC pursuant to Requirement R4, in the operational performance analysis conducted by the RAS-entity pursuant to Requirement R5, or in the functional test performed by the RAS-entity pursuant to Requirement R8, potentially pose a reliability risk to the BES. To mitigate these potential reliability risks, Requirement R6 mandates that each RAS-entity develop a Corrective Action Plan (CAP) to address the identified deficiency. The CAP contains the mitigation actions and associated timetable necessary to remedy the specific deficiency. The RAS-entity may request assistance with CAP development from other parties such as its Transmission Planner or Planning Coordinator; however, the RAS-entity has the responsibility for compliance with this requirement.

If the CAP requires that a functional change be made to a RAS, the RAS-entity will need to submit information identified in Attachment 1 to the reviewing RC(s) prior to placing RAS modifications in service per Requirement R1.

Depending on the complexity of the identified deficiency(ies), development of a CAP may require studies, and other engineering or consulting work. A maximum time frame of six full calendar months is specified for RAS-entity collaboration on the CAP development. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to develop and submit a single, coordinated CAP.

Rationale for Requirement R7: Requirement R7 mandates each RAS-entity implement a CAP (developed in Requirement R6) that mitigates the deficiencies identified in Requirements R4, R5, or R8. By definition, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem." The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. Each reviewing Reliability Coordinator must be notified if CAP actions or timetables change, and when the CAP is completed.

Rationale for Requirement R8: Due to the wide variety of RAS designs and implementations, and the potential for impacting BES reliability, it is important that periodic functional testing of a RAS be performed. A functional test provides an overall confirmation of the RAS to operate as designed and verifies the proper operation of the non-Protection System (control) components of a RAS that are not addressed in PRC-005. Protection System components that are part of a RAS are maintained in accordance with PRC-005.

The six or twelve full calendar year test interval, which begins on the effective date of the standard pursuant to the PRC-012-2 implementation plan, is a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS. Extending to longer intervals increases the reliability risk to the BES posed by an undiscovered latent failure that could cause an incorrect operation or failure of the RAS. The RAS-entity is in the best position to determine the testing procedure and schedule due to its overall knowledge of the RAS design, installation, and functionality. Functional testing may be accomplished with end-to-end testing or a segmented approach. For segmented testing, each segment of a RAS must be tested. Overlapping segments can be tested individually negating the need for complex maintenance schedules and outages.

The maximum allowable interval between functional tests is six full calendar years for RAS that are not designated as limited impact RAS and twelve full calendar years for RAS that are designated as limited impact RAS. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. A correct operation of a RAS qualifies as a functional test for those RAS segments which operate (documentation for compliance with Requirement R5 Part 5.1). If an event causes a partial operation of a RAS, the segments without an operation will require a separate functional test within the maximum interval with the starting date determined by the previous successful test of the segments that did not operate.

Rationale for Requirement R9: The RAS database is a comprehensive record of all RAS existing in a Reliability Coordinator Area. The database enables the RC to provide other entities high-level information on existing RAS that could potentially impact the operational and/or planning activities of that entity. Attachment 3 lists the minimum information required for the RAS database, which includes a summary of the RAS initiating conditions, corrective actions, and System issues being mitigated. This information allows an entity to evaluate the reliability need for requesting more detailed information from the RAS-entities identified in the database contact information. The RC is the appropriate entity to maintain the database because the RC receives the required database information when a new or modified RAS is submitted for review. The twelve full calendar month time frame is aligned with industry practice and allows sufficient time for the RC to collect the appropriate information from RAS-entities and update the RAS database.

Exhibit C

Implementation Plan for PRC-012-2

Implementation Plan for PRC-012-2

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

Requested Approval

- PRC-012-2 – Remedial Action Schemes

Requested Withdrawals

- PRC-012-1 – Remedial Action Scheme Review Procedure
- PRC-013-1 – Remedial Action Scheme Database
- PRC-014-1 – Remedial Action Scheme Assessment

Requested Retirements

- PRC-015-1 – Remedial Action Scheme Data and Documentation
- PRC-016-1 – Remedial Action Scheme Misoperations

Applicable Entities

- Reliability Coordinator
- Planning Coordinator
- RAS-entity – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS

Background

On November 13, 2014, the NERC Board of Trustees approved revisions to the definition for Remedial Action Scheme ("RAS") and associated revisions to related Reliability Standards to consolidate that term with the Glossary term "Special Protection System" (SPS).

In its February 3, 2015 petition to the Commission for approval of the definition of RAS and associated Reliability Standards ("Petition"), NERC noted that, although PRC-012-0, PRC-013-0, and PRC-014-0 were neither approved nor remanded by the Commission in Order No. 693 and were therefore not enforceable, NERC revised these standards to account for the RAS definition revision and changed relevant version numbers to reflect the change. Because of this change, NERC requested retirement of PRC-012-0, PRC-013-0, and PRC-014-0, and provided, for informational purposes only, updated Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1. In the same Petition, NERC requested retirement of PRC-015-0 and PRC-016-0.1 and approval of Reliability Standards PRC-015-1 and PRC-016-1, again implementing changes stemming from the revised definition of RAS.

On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to accept the revisions to the RAS definition and associated standards, and on November 19, 2015, the Commission issued a Final Order approving the RAS definition and associated standards.

General Considerations

Reliability Standard PRC-012-2 was developed to consolidate previously unapproved standards which were designated by the Commission as "fill-in-the-blank" standards and to revise other RAS-related standards. Reliability Standard PRC-012-2 also provides clear and unambiguous responsibilities to the specific users, owners, and operators of the Bulk-Power System. Reliability Standard PRC-012-2 establishes a new working framework between RAS-entities, PCs, and RCs, and this new framework will involve considerable start-up effort. As such, implementation of Reliability Standard PRC-012-2 will occur over a thirty six (36) month period after approval of the standard by applicable governmental authorities.

Limited Impact RAS

A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type III in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 and is subject to all applicable requirements.

Effective Date

Where approval by an applicable governmental authority is required, Reliability Standard PRC-012-2 shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. Provisions concerning the initial performance of obligations under Requirements R4, R8, and R9 are outlined below.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction. Provisions concerning the initial performance of obligations under Requirements R4, R8, and R9 are outlined below.

Requirement R4

For existing RAS, initial performance of obligations under Requirement R4 must be completed within five (5) full calendar years after the effective date of PRC-012-2, as described above.

For new or functionally modified RAS, the initial performance of Requirement R4 must be completed within five (5) full calendar years after the date that the RAS is approved by the reviewing RC(s) under Requirement R3.

Requirement R8

For each RAS not designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within six (6) full calendar years after the effective date for PRC-012-2, as described above.

For each RAS designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within twelve (12) full calendar years after the effective date for PRC-012-2, as described above.

Requirement R9

For each Reliability Coordinator that does not have a RAS database, the initial obligation under Requirement R9 is to establish a database by the effective date of PRC-012-2.

Each Reliability Coordinator will perform the obligation of Requirement R9 within twelve full calendar months after the effective date of PRC-012-2, as described above.

Retirement of Existing Standards

The Reliability Standards for retirement shall be retired immediately prior to the effective date of PRC-012-2 in the particular jurisdiction in which the standard is becoming effective.

Exhibit D

Analysis of Violation Risk Factors and Violation Severity Levels for PRC-012-2

Violation Risk Factor and Violation Severity Level Justification Document

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

This document provides the standard drafting team (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-012-2. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for PRC-012-2, Requirement R1	
VRF for Requirement R1 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of an entity to submit Attachment 1 information to the responsible Reliability Coordinator for review prior to placing a new or modified RAS in service or retiring an existing RAS could introduce risks to the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R1 relates to two of these areas, specifically (i) protection systems and their coordination; and (ii) clearer criteria for operationally critical facilities. Requirement R1 mandates that entities comply with a review process for new or modified RAS or retirement of RAS. Among the elements of such reviews is the coordination between RAS and other RAS and between RAS and protection and control systems. Requirement R1 also mandates that the RAS-entity provide the Reliability Coordinator relevant RAS information regarding the design and implementation for each new or functionally modified RAS.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements, so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-012-1, Requirement 1, Parts R1.1 – R1.5 which specifies attributes of the RRO process to review RAS (R1.1), provision of pertinent RAS data (R1.2), dependability (R1.3) and security (R1.4) of design, and coordination with other RAS and protection systems (R1.5), and has a Medium VRF.
FERC VRF G4 Discussion	A medium VRF is appropriate for this requirement because failure of an entity to submit Attachment 1 information to the responsible Reliability Coordinator for review prior to placing a new or modified RAS in

VRF Justifications for PRC-012-2, Requirement R1	
VRF for Requirement R1 is Medium	
Guideline 4- Consistency with NERC Definitions of VRFs	service or retiring an existing RAS could introduce risks to the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The RAS-entity failed to provide the information identified in Attachment 1 to each Reliability Coordinator prior to placing a new or functionally modified RAS in service or retiring an existing RAS in accordance with Requirement R1.

VSL Justifications for PRC-012-2, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-012-1, Requirements R1.1 – R1.5 which had four established Levels of Non-Compliance. The requirement is binary with only a Severe VSL so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2b: N/A
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R2	
VRF for Requirement R2 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R2 because failure of a Reliability Coordinator to perform the RAS reviews and identify potential risks presented by the RAS could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R2 relates to one of these areas, specifically, protection systems and their coordination. Requirement R2 mandates that Reliability Coordinators review the RAS to determine if a RAS avoids adverse interactions with other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-014-1, Requirement R1, which is related to the review of RAS.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R2 because failure of a Reliability Coordinator to perform the RAS reviews and identify potential risks presented by the RAS could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R2	
VRF for Requirement R2 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90 full calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in accordance with Requirement R2.

VSL Justifications for PRC-012-2, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-014-0, Requirement R1 which also had four established Levels of Non-Compliance. This requirement has VSLs comparable to the established Levels of Non-Compliance in that requirement, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R3	
VRF for Requirement R3 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of a RAS entity to address the reliability issues identified during the RC review before placing it into service could introduce risks to the BES that could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R3 relates to one of these areas, specifically protection systems and their coordination. Requirement R3 requires the RAS-entity to address each identified reliability issue which includes the coordination between RAS and other RAS and between RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-015-0 Requirement R2 which requires the entity to comply with the RRO procedure as defined in PRC-012-1 Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of a RAS entity to address the reliability issues identified during the RC review before placing it into service could introduce risks to the BES that could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R3	
VRF for Requirement R3 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The RAS-entity failed to resolve identified reliability issue(s) to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in service or retiring an existing RAS in accordance with Requirement R3.

VSL Justifications for PRC-012-2, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-015-0, Requirement R2 which has four established VSLs. This requirement is binary with only a Severe VSL so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2b: N/A
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R4	
VRF for Requirement R4 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R4 because failure to perform the periodic evaluation could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R4 relates to one of these areas, specifically protection systems and their coordination. Requirement R4 mandates that entities perform periodic evaluations of each RAS to ensure that changes in System conditions have not changed the effectiveness of the RAS to mitigate the events or System conditions for which it was designed. Requirement R4 incorporates all actions necessary to determine if a RAS avoids adverse interactions with other RAS and protection and control systems
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-2, Requirement R3 which requires the assessment of the effectiveness of UVLS Programs.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R4 because failure to perform the periodic evaluation could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R4	
VRF for Requirement R4 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator performed the evaluation as specified in Requirement R4, but was late by less than or equal to 30 full calendar days.	The Planning Coordinator performed the evaluation as specified in Requirement R4, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Planning Coordinator performed the evaluation as specified in Requirement R4, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate one of the Parts 4.1.1 through 4.1.5.	The Planning Coordinator performed the evaluation as specified in Requirement R4, but was late by more than 90 full calendar days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate two or more of the Parts 4.1.1 through 4.1.5. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to provide the results to one or more of the

VSLs for PRC-012-2, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
			receiving entities listed in Part 4.2. OR The Planning Coordinator failed to perform the evaluation in accordance with Requirement R4.

VSL Justifications for PRC-012-2, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-014-0, Requirement R1 which has four established Levels of Non-Compliance. This requirement has comparable VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R4	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R4	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R5	
VRF for Requirement R5 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R5 because failure to perform the RAS operational performance analysis could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R5 relates to one of these areas, specifically protection systems and their coordination. Requirement R5 mandates that entities perform RAS operational performance analysis to verify that the RAS operation and the resulting System performance was consistent with the Contingency events or System conditions for which it was designed. Requirement R5 incorporates all actions necessary to identify coordination issues between RAS and other RAS and between RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-2, Requirements R4 which requires evaluation of the UVLS Program performance during a voltage excursion event.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R5 because failure to perform the RAS operational performance analysis could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R5	
VRF for Requirement R5 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity performed the analysis in accordance with Requirement R5, but was late by less than or equal to 10 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address one of the Parts 5.1.1 through 5.1.4.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address two or more of the Parts 5.1.1 through 5.1.4. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to provide the results (Part 5.2) to one or more of the reviewing Reliability Coordinator(s).

VSLs for PRC-012-2, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
			OR The RAS-entity failed to perform the analysis in accordance with Requirement R5

VSL Justifications for PRC-012-2, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0.1, Requirement R1, and PRC-012-1, Requirement R1.7, which have four established Levels of Non-Compliance. This requirement has comparable VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R5	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R5	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R6	
VRF for Requirement R6 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because the failure of an entity to develop a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R6 addresses one of these areas, specifically protection systems and their coordination. CAPs establish mitigation plans and timetable to address deficiencies that could cause adverse interactions between RAS and other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-016-0, Requirements R2 and R3 which require a RAS-owner take corrective actions to avoid future misoperations and provide documentation of the corrective action plans to the RRO.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because the failure of an entity to develop a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

VRF Justifications for PRC-012-2, Requirement R6	
VRF for Requirement R6 is Medium	
	preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30 full calendar days. OR The RAS-entity developed a Corrective Action Plan but failed to submit it to one or more of its reviewing Reliability Coordinator(s) in accordance with Requirement R6. OR

VSLs for PRC-012-2, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
			The RAS-entity failed to develop a Corrective Action Plan in accordance with Requirement R6.

VSL Justifications for PRC-012-2, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0, Requirements R2 and R3, and has VSLs comparable to the established Levels of Non-Compliance in those requirements, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R6	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R6	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R7	
VRF for Requirement R7 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of an entity to implement a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R7 relates to one of these areas, specifically protection systems and their coordination. Implemented CAPs address deficiencies that could cause adverse interactions between RAS and other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-016-0, Requirements R2 and R3 which require a RAS-owner take corrective actions to avoid future misoperations and provide documentation of the corrective action plans to the RRO.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of an entity to implement a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

VRF Justifications for PRC-012-2, Requirement R7	
VRF for Requirement R7 is Medium	
	preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity implemented a CAP in accordance with Requirement R7, Part 7.1, but failed to update the CAP (Part 7.2) if actions or timetables changed, or failed to notify (Part 7.3) each of the reviewing Reliability Coordinator(s) of the updated CAP or completion of the CAP.	N/A	N/A	The RAS-entity failed to implement a CAP in accordance with Requirement R7, Part 7.1.

VSL Justifications for PRC-012-2, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0, Requirement R2 and has VSLs comparable to the established Levels of Non-Compliance in that requirement, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Lower and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R8	
VRF for Requirement R8 is High	
NERC VRF Discussion	A High VRF is appropriate for this Requirement since failure to perform functional testing may allow latent failures to persist in a RAS. These latent failures could result in an unintended operation or a failure to operate, either of which could directly contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures. For these reasons, the requirement meets the NERC criteria for a High VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R8 has interactions in three of these areas, specifically (i) protection systems and their coordination, (ii) communication protocol and facilities, and (iii) appropriate use of transmission loading relief. RAS interactions occur with protection systems, utilize communication protocols and facilities for proper functioning, and are often used for transmission loading relief.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements, so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-005-3, Requirement R3 which requires the maintenance of Protection System Components and has a VRF of High.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A High VRF is appropriate for this Requirement since failure to perform functional testing may allow latent failures to persist in a RAS. These latent failures could result in an unintended operation or a failure to operate, either of which could directly contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures. For these reasons, the requirement meets the NERC criteria for a High VRF.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VRF Justifications for PRC-012-2, Requirement R8	
VRF for Requirement R8 is High	
mingle More than One Obligation	

VSLs for PRC-012-2, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by less than or equal to 30 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 90 full calendar days. OR The RAS-entity failed to perform the functional test for a RAS as specified in Requirement R8.

VSL Justifications for PRC-012-2, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-017-0, Requirements R1 and R2, which had VSLs of Lower, Moderate, High, and Severe. This requirement has VSLs comparable to the established VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R8	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R9	
VRF for Requirement R9 is Lower	
NERC VRF Discussion	A Lower VRF is appropriate for this requirement because the failure of an entity to update the RAS database, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R9 does not address any of the identified areas; therefore, the FERC VRF G1 Discussion is not applicable.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with PRC-010-2 Requirement R6 and PRC-006-1 Requirement R6, which have an approved VRF of Lower.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A Lower VRF is appropriate for this requirement because the failure of an entity to update the RAS database, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90 full calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

VSL Justifications for PRC-012-2, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-013-0, Requirement R1 and has VSLs comparable to the established Levels of Non-Compliance of that requirements, so there is no consequence of lowering the current level of compliance.

VSL Justifications for PRC-012-2, Requirement R9	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations**FERC VSL G3** Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is based upon a single violation, not a cumulative number of violations.The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

Exhibit E

Mapping Document for PRC-012-2

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Mapping Document

Project 2010-5.3 Phase 3 of Protection Systems: Remedial Action Schemes

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include: **R1.1.** Description of the process for submitting a proposed RAS for Regional Reliability Organization review. **R1.2.** Requirements to provide data that describes design, operation, and modeling of a RAS. **R1.3.** 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.	**PRC-012-1 R.1.1**: Covered by Requirements R1, R2 and R3 **PRC-012-1 R.1.2**: Covered by Requirement R1, Attachment 1 **PRC-012-1 R.1.3**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4, Part 4.1.5 **PRC-012-1 R.1.4**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2, and Requirement R4, Part 4.1.4	**R1.** Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. **R3.** Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator. **R4.** Each Planning Coordinator, at least once every five full calendar years, shall:

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1.4. Requirements to demonstrate 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. **R1.5.** Requirements to demonstrate the proposed RAS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures. **R1.6.** Regional Reliability Organization definition of misoperation. **R1.7.** Requirements for analysis and documentation of corrective action plans for all RAS misoperations. **R1.8.** Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure. **R1.9.** Determination, as appropriate, of maintenance and testing requirements.	**PRC-012-1 R.1.5**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4, Part 4.1.2 **PRC-012-1 R.1.6**: Covered by Requirement R5 **PRC-012-1 R.1.7**: Covered by Requirements R5 and R6 **PRC-012-1 R.1.8**: PRC-012-2 NERC Standards Development Process **PRC-012-1 R.1.9**: Covered by Requirement R8	**4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for limited impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.4.1** The BES shall remain stable. **4.1.4.2** Cascading shall not occur. **4.1.4.3** Applicable Facility Ratings shall not be exceeded. **4.1.4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		established by the Transmission Planner and the Planning Coordinator. **4.1.4.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator. **R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether:

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		5.1.1 The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s). **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R8.** Each RAS-entity shall participate in performing a functional test of each of its RAS to verify the overall RAS

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		performance and the proper operation of non-Protection System components: • At least once every six full calendar years for all RAS not designated as limited impact, or • At least once every twelve full calendar years for all RAS designated as limited impact
R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-013-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a RAS installed shall maintain a RAS database. The database shall include the following types of information:	**<u>PRC-013-1 R1</u>**: Covered by Requirement R9 **<u>PRC-013-1 R1.1, R1.2, R1.3:</u>** Covered by Requirement R9, Attachment 3	**R9.** Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once every twelve full calendar months.

Reliability Standard: PRC-013-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1.1. Design Objectives — Contingencies and system conditions for which the RAS was designed, **R1.2.** Operation — The actions taken by the RAS in response to Disturbance conditions, and **R1.3.** Modeling — Information on detection logic or relay settings that control operation of the RAS.		
R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years	**PRC-014-1 R1**: Covered by Requirement R4	**R4.** Each Planning Coordinator, at least once every five full calendar years, shall:

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
for compliance with NERC Reliability Standards and Regional criteria.		**4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for limited impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.4.1** The BES shall remain stable. **4.1.4.2** Cascading shall not occur. **4.1.4.3** Applicable Facility Ratings shall not be exceeded. **4.1.4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		established by the Transmission Planner and the Planning Coordinator. **4.1.4.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.
R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all RAS installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).	<u>**PRC-014-1 R2**</u>: Covered by Requirement R4	**R4.** Each Planning Coordinator, at least once every five full calendar years, shall: **4.1** Perform an evaluation of each RAS within its planning area to determine whether:

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.1.1 The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for limited impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.4.1** The BES shall remain stable. **4.1.4.2** Cascading shall not occur. **4.1.4.3** Applicable Facility Ratings shall not be exceeded. **4.1.4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.1.4.5 Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.
R3. The documentation of the Regional Reliability Organization's RAS assessment shall include the following elements: **R3.1.** Identification of group conducting the assessment and the date the assessment was performed. **R3.2.** Study years, system conditions, and contingencies analyzed in the technical studies on which the	**PRC-014-1 R3**: Covered by Requirement R4 **PRC-014-1 R3.1 - R3.4**: Covered by Requirement R4 **PRC-014-1 R3.5**: Covered by Requirement R6	**R4.** Each Planning Coordinator, at least once every five full calendar years, shall: **4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
assessment is based and when those technical studies were performed. **R3.3.** Identification of RAS that were found not to comply with NERC standards and Regional Reliability Organization criteria. **R3.4.** Discussion of any coordination problems found between a RAS and other protection and control systems. **R3.5.** Provide corrective action plans for non-compliant RAS.		**4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for limited impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.4.1** The BES shall remain stable. **4.1.4.2** Cascading shall not occur. **4.1.4.3** Applicable Facility Ratings shall not be exceeded. **4.1.4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. **4.1.4.5** Transient voltage responses shall be within acceptable limits as established by the

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		Transmission Planner and the Planning Coordinator. **4.1.5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator. **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8.

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall maintain a list of and provide data for existing and proposed RAS as specified in Reliability Standard PRC-013-1 R1.	**PRC-015-1 R1**: Covered by Requirement R1, Attachment 1	**R1.** Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located.
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-1_R1 prior to being placed in service.	**PRC-015-1 R2**: Covered by Requirements R1, Attachment 1; R2, Attachment 2; and R3	**R1.** Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. **R3.** Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide	Retired P81	N/A

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
documentation of RAS data and the results of Studies that show compliance of new or functionally modified RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).		

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall analyze its RAS operations and maintain a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-1_R1.	**PRC-016-1 R1**: Covered by Requirement R5	**R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall take corrective actions to avoid future misoperations.	**PRC-016-1 R2**: Covered by Requirements R6 and R7	**R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of:

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		• Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R7.** Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: **7.1** Implement the CAP. **7.2** Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).	**PRC-016-1 R3**: Covered by Requirements R5, R6, and R7, Attachment 1	**R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS.

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		5.1.2 The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s). **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R7.** Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: **7.1** Implement the CAP.

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		7.2 Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

Exhibit F

Reliability Standard PRC-012-2 Remedial Action Schemes

Question & Answer Document

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

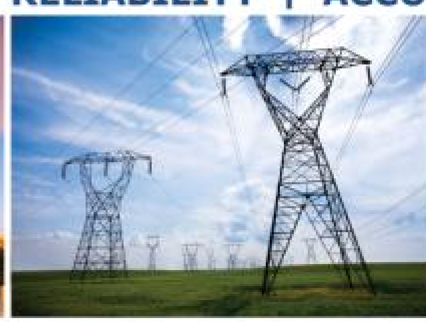
Reliability Standard PRC-012-2 Remedial Action Schemes Question & Answer Document

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

April 2016

RELIABILITY | ACCOUNTABILITY



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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 is the Remedial Action Scheme (RAS) review assigned to the Reliability Coordinator?

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 Reliability Coordinators (RCs) and Planning Coordinators (PCs) 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. The Wide Area purview 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, Planning Coordinator, Transmission Planner, or other entities 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 is not expected to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not contain compliance requirements. If Reliability Standards address functions that are not described in the model, the Reliability Standard requirements take precedence over the Functional Model. For further reference, please see the Introduction section of NERC’s Reliability Functional Model, Version 5, November 2009. 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 five year evaluation of Requirement R4 assigned to the Planning Coordinator?

Requirement R4 states that an evaluation of each RAS must be done at least once every five full calendar years 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, similar to the planning analyses performed by PCs.

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

TOP-1-3 Requirement R13 requires Balancing Authorities (BA) and Transmission Operators (TOP) 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-005-4 requires RCs to share any pertinent data, such as data from RAS, with potentially affected BAs and TOPs. 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.

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

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 the RAS-entities. 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?

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 4.1.5 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.

Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review processes and designated as Type III in NPCC or Local Area Protection Scheme (LAPS) in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process. Limited impact schemes are not subject to the single component failure aspect of Requirement R4, Part 4.1.5.

6. What is required for RAS "inadvertent operation" and why?

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-012-1 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 4.1.4 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 4.1.4.1 – 4.1.4.5, which are the performance requirements common to all planning events P0–P7.

Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective

date of this standard that has been through the regional review processes and designated as Type III in NPCC or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator in conjunction with the RAS review process. Limited impact schemes are not subject to the single component malfunction aspect of Requirement R4, Part 4.1.4.

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 for continuity with PRC-012-1 R1.3; however, the standard drafting team concluded the classification is unnecessary. The distinction between planning and extreme RAS is captured in Requirement R4, Part 4.1.5 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.

Similarly, the standard drafting team concluded that the SPCS-SAMS distinction between significant and limited RAS was unnecessary for the purpose of maintaining continuity with PRC-012-1, and problematic due to the difficulty of drawing a universally satisfactory delineation in generally worded classification criteria. Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review processes and designated as Type III in NPCC or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator in conjunction with the RAS review process.

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 a functional modification of a RAS?

A functional modification to a RAS consists of any of the following:

- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels (addition or removal)

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 device custom logic.
2. Changes to the telecommunication infrastructure or communication facility, such as the replacement of a T1 multiplexor that carries RAS communication when such changes may be important to the 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, or a component that uses the same functionality as the failed component.
2. A firmware upgrade of a RAS component if the change does not require changes in the RAS implementation logic.

The Supplemental Material section of Reliability Standard PRC-012-2 also includes several additional examples of RAS changes that do and do not constitute functional modifications.

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
NERC Staff	Al McMeekin (Standards Developer)	NERC
NERC Staff	Lacey Ourso (Standards Developer)	NERC
NERC Staff	Andrew Wills (Associate Counsel)	NERC

Exhibit G

Order No. 672 Criteria

Order No. 672 Criteria

In Order No. 672, the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest.[1] The discussion below identifies these factors and explains how the revisions reflected in proposed Reliability Standard has met or exceeded the criteria.

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]

The proposed Reliability Standard PRC 012-2, attached as Exhibit B, achieves specific reliability goals using sound methods to achieve those goals. The purpose of proposed Reliability Standard PRC 012-2—Remedial Action Schemes is "to ensure that Remedial Action Schemes ("RAS") do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System ("BES")." Proposed Reliability Standard PRC 012-2 accomplishes its goal by establishing requirements for Reliability Coordinators ("RC"), Planning Coordinators ("PC"), and RAS-entities to manage RAS connected to the BES by reviewing, evaluating, analyzing, testing, and addressing issues associated with each RAS.

Existing effective Reliability Standards require RAS owners to collect data regarding each of their RAS, analyze RAS operations, and take corrective actions to avoid misoperations. However, reliability would be improved by instituting requirements on affected entities to periodically review and maintain RAS and to collect relevant information about each RAS. Proposed Reliability Standard PRC-012-2 would accomplish these goals by ensuring (i) that the

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at PP 321, 324.

RC, as the entity with a widest area perspective, reviews and approves each RAS before placing the RAS into operation, (ii) that affected entities periodically review, test, and evaluate each RAS, and (iii) that the RC maintains a database of each RAS in its RC area. By using a defense-in-depth approach, the proposed Reliability Standard improves the reliability of the BES.

2. **Proposed Reliability Standards must be applicable only to users, owners, and operators of the Bulk Power System, and must be clear and unambiguous as to what is required and who is required to comply.[3]**

The proposed Reliability Standard is applicable only to users, owners, and operators of the Bulk Power System and is clear and unambiguous as to what is required and who is to comply, in accordance with Order No. 672. The proposed Reliability Standard applies to the Reliability Coordinator, Planning Coordinator, and RAS entities.[4] The proposed Reliability Standard clearly states who is required to comply with the standard and what is required, in accordance with Order No. 672.

3. **A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[5]**

The Violation Risk Factor ("VRF") and Violation Severity Level ("VSL") for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment. The assignment of the severity level of each VSL is consistent with the corresponding Requirement and will ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed

[3] Order No. 672, at PP 322, 325.

[4] Section 4 of PRC-012-2 explains that a RAS-entity is "the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS."

[5] Order No. 672 at P 327.

Reliability Standard includes clear an understandable consequences in accordance with Order No. 672.

4. **A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced with consistence and with no preference.**[6]

The proposed Reliability Standard contains Measures that support each Requirement by clearly identifying what is required to demonstrate compliance and how the Requirement will be enforced. The Measures are as follows:

> M1. Acceptable evidence may include, but is not limited to, a copy of the Attachment 1documentation and the dated communications with the reviewing Reliability Coordinator(s) in accordance with Requirement R1.
>
> M2. Acceptable evidence may include, but is not limited to, dated reports, checklists, or other documentation detailing the RAS review, and the dated communications with the RAS-entity in accordance with Requirement R2.
>
> M3. Acceptable evidence may include, but is not limited to, dated documentation and communications with the reviewing Reliability Coordinator that no reliability issues were identified during the review or that all identified reliability issues were resolved in accordance with Requirement R3.
>
> M4. Acceptable evidence may include, but is not limited to, dated reports or other documentation of the analyses comprising the evaluation(s) of each RAS and dated communications with the RAS entity(ies), Transmission Planner(s), Planning Coordinator(s), and the reviewing Reliability Coordinator(s) in accordance with Requirement R4.
>
> M5. Acceptable evidence may include, but is not limited to, dated documentation detailing the results of the RAS operational performance analysis and dated communications with participating RAS-entities and the reviewing Reliability Coordinator(s) in accordance with Requirement R5.
>
> M6. Acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each reviewing Reliability Coordinator and each RAS-entity in accordance with Requirement R6.
>
> M7. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, setting sheets, work orders, maintenance records, and communication with the reviewing Reliability Coordinator(s) that

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6 Order No. 672 at P 327.

documents the implementation, updating, or completion of a CAP in accordance with Requirement R7.

M8. Acceptable evidence may include, but is not limited to, dated documentation detailing the RAS operational performance analysis for a correct RAS segment or an end-to-end operation (Measure M5 documentation), or dated documentation demonstrating that a functional test of each RAS segment or an end-to-end test was performed in accordance with Requirement R8.

M9. Acceptable evidence may include, but is not limited to, dated spreadsheets, database reports, or other documentation demonstrating a RAS database was updated in accordance with Requirement R9.

The above Measures work in coordination with the respective Requirements to ensure that the Requirements will each be enforced in a clear, consistent, and non-preferential manner without prejudice to any party.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[7]

Proposed Reliability Standard PRC 012-2 achieves the reliability goals effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standard improves reliability by instituting oversight measures for RAS, thus creating a continent-wide RAS program to improve communications and security associated with these devices. The proposed Reliability Standard will also establish a new working framework between RAS-entities, PCs, and RCs that establishes clear responsibilities and results in a new efficient system that prevents risks to the reliability of the Bulk Power System.

6. Proposed Reliability Standards cannot be "lowest common denominator," *i.e.,* cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[8]

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[7] Order No. 672, at P 328.
[8] Order No. 672, at PP 329-330.

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. To the contrary, the proposed standard represents significant benefits for the reliability of the Bulk Power System because it institutes Requirements that will lead to a decrease in risk to the BES through review, testing, evaluations, and improvements to RAS. In doing so, the proposed Reliability Standard does not sacrifice excellence in operating system reliability for costs associated with implementation of the Reliability Standard.

7. **Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard**.[9]

The proposed Reliability Standard applies throughout North America and does not favor one geographic area or regional model.

8. **Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability**.[10]

The proposed Reliability Standard has no undue negative effect on competition nor results in any unnecessary restrictions.

9. **The implementation time for the proposed Reliability Standard is reasonable**.[11]

The proposed effective date for the standard is just and reasonable and appropriately balances the urgency in the need to implement the standard against the reasonableness of the time allowed

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[9] Order No. 672, at P 331.

[10] Order No. 672, at P 332. As directed by section 215 of the FPA, FERC itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

[11] Order No. 672, at P 333.

for those who must comply to develop necessary procedures, software, facilities, staffing or other relevant capability. NERC proposes an effective date for PRC-012-2 on the first day of the first calendar quarter that is thirty-six (36) months after the effective date of the applicable regulatory approval. The proposed implementation period is designed to allow sufficient time for the applicable entities to make any changes in their staffing or internal processes necessary to implement the proposed review, evaluation, and testing procedures. The proposed effective date is explained in the proposed Implementation Plan, attached as **Exhibit C**.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[12]

The proposed Reliability Standard was developed in accordance with NERC's Commission approved, ANSI-accredited processes for developing and approving Reliability Standards.[13] **Exhibit H** includes a summary of the standard development proceedings, and details the processes followed to develop the Reliability Standard. These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the standard drafting team were properly noticed and open to the public.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[14]

NERC has not identified competing public interests regarding the request for approval of the proposed Reliability Standard PRC 012-2. No comments were received that indicated the proposed Reliability Standard conflict with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[15]

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[12] Order No. 672, at P 334.

[13] *See* NERC Rules of Procedure, Section 300 (Reliability Standards Development) and Appendix 3A (Standard Processes Manual).

[14] Order No. 672, at P 335.

[15] Order No. 672, at P 323.

No other factors relevant to whether the proposed Reliability Standard PRC 012-2 are just and reasonable were identified.

Exhibit H

Summary of Development History and Complete Record of Development

Summary of Development History

The development record for proposed Reliability Standard PRC-012-2 is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team selected to lead each project in accordance with Section 4.3 of the NERC Standards Process Manual.[2] For this project, the standards drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the standard drafting team members is included in **Exhibit I.**

II. Standard Development History

A. Standards Authorization Request Development

On February 12, 2014, NERC submitted a Standard Authorization Request ("SAR") to the NERC Standards Committee ("SC") to revise the NERC Glossary definition for Special Protection System ("SPS") and to revise or develop SPS-related Reliability Standards. The SC authorized the posting of the SAR for Project 2010-05.2 on February 12, 2014, and NERC posted the SAR for a 30-day comment period from February 18, 2014 through March 19, 2014. NERC later divided the work anticipated by the SAR for Project 2010-05.2 into two phases, Project 2010-05.2 and Project 2010-05.3, to address NERC Glossary definition revisions ahead of developing a Reliability Standard for planning, coordination, and design of Remedial Action Schemes ("RAS").

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1 Section 215(d)(2) of the Federal Power Act; 16 U.S.C. § 824(d)(2) (2012).

2 The NERC *Standard Processes Manual* is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

B. Unofficial Comment Period

Proposed Reliability Standard PRC-012-2 was posted for an initial comment period from April 30, 2015 through May 20, 2015.[3]

C. First Posting - Comment Period and Initial Ballot

After the unofficial comment period, the first official draft of proposed Reliability Standard PRC-012-2 was posted for a 45-day public comment period from August 20, 2015, through October 5, 2015, with an initial ballot and non-binding poll held from September 25, 2015, through October 5, 2015. Several documents were posted with the first draft, including the Implementation Plan for Reliability Standard PRC-012-2, an associated Question and Answer Document, the Mapping Document for PRC-012-2, and the Violation Risk Factor and Violation Severity Level Justification Document. There were 60 responses, including comments from approximately 155 different people, and approximately 104 different companies representing nine of the ten Industry Segments.[4] The initial ballot reached quorum at 83.96% of the ballot pool and received votes of approval from 48.11% of the voters.

D. Second Posting – Comment Period and Additional Ballot

Proposed Reliability Standard PRC-012-2 was posted for a 45-day formal comment period from November 25, 2015, through January 8, 2018, with an additional parallel 10-day ballot and Non-binding Poll held from December 30, 2015, until January 8, 2016. Updated versions of the associated Implementation Plan, Question and Answer Document, Mapping Document, and the Violation Risk Factor and Violation Severity Level Justification Document

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[3] NERC, *Survey Report*, Project 2010-05.3 (May 20, 2015) available at http://www.nerc.com/pa/Stand/Prjct201005_3RmdialActnSchmsPhase3ofPrtctnSystmsDL/2010-05.3_Phase_3_of%20Protection_Systems_RAS_Comments_Received_Report_05272015.pdf.

[4] NERC, *Consideration of Comments*, Project 2010-05.3 (Nov. 25, 2015), *available at* http://www.nerc.com/pa/Stand/Prjct201005_3RmdialActnSchmsPhase3ofPrtctnSystmsDL/2010-05_3_RAS_PRC-012-2_Consideration_of_Comments_11252015_final.pdf.

were also posted with the second draft. There were 46 responses, including comments from approximately 150 different people from approximately 98 different companies representing nine of the ten Industry Segments.[5] The additional ballot reached quorum at 83.39% of the ballot pool and received votes of approval from 60.39% of the voters.

E. Third Posting – Comment Period and Additional Ballot

Proposed Reliability Standard PRC-012-2 was posted for a 45-day formal comment period from February 3, 2016, through March 18, 2016, with an additional parallel ballot held from March 9, 2016 through March 18, 2016. Updated versions of the associated Implementation Plan, the Question and Answer Document, Mapping Document, Violation Risk Factor and Violation Severity Level Justification Document, and Unofficial Comment Form were also posted with the third draft. There were 43 sets of responses, including comments from approximately 41 different people, approximately 39 companies representing eight of the Industry Segments.[6] The additional ballot reached quorum at 75.55% of the ballot pool and received votes of approval from 78.87% of the voters.

F. Final Ballot

Proposed Reliability Standard PRC-012-2 was posted for a 10-day final ballot period from April 20, 2016, through April 29, 2016. The proposed Reliability Standard received adequate votes for approval, reaching quorum at 81.19% of the ballot body and receiving votes of approval from 80.36% of the voters.[7]

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[5] NERC, *Consideration of Comments*, Project 2010-05.3 (Feb. 3, 2016), *available at* http://www.nerc.com/pa/Stand/Prjct201005_3RmdialActnSchmsPhase3ofPrtctnSystmsDL/2010-05_3_RAS_PRC-012-2_C_of_C_02032016.pdf.

[6] NERC, *Consideration of Comments*, Project 2010-05.3 (Apr. 20, 2016), *available at* http://www.nerc.com/pa/Stand/Prjct201005_3RmdialActnSchmsPhase3ofPrtctnSystmsDL/2010-05.3_RAS_Comments_Received_Report_03222016.pdf.

[7] NERC, *Standards Announcement*, Project 2010-05.3, available at http://www.nerc.com/pa/Stand/Prjct201005_3RmdialActnSchmsPhase3ofPrtctnSystmsDL/2010-05.3_PRC-012-2_FB_Results_Word_Announce_05032016.pdf.

G. Board of Trustees Adoption

Proposed Reliability Standard PRC-012-2 was adopted by the NERC Board of Trustees on May 5, 2016.

Complete Record of Development

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

Related Files | 2010-05.2 Phase 2 of Protection Systems

Status

Final ballots for **PRC-012-2 – Remedial Action Schemes** and the **Revised Definition of "Special Protection System"** concluded **8 p.m. Eastern, Friday, April 29, 2016.** The voting results can be accessed via the links below. The standard and definition will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background

In early 2011, NERC staff decided to divide Project 2010-05: Protection Systems into phases. Phase 1 addressed the Misoperations of Protection Systems and was adopted by the NERC BOT on August 14, 2014. Phase 2 revised the definition of Remedial Action Scheme (RAS) and was adopted by the NERC BOT on November 13, 2014. Phase 3 is intended to address all aspects of RAS and Special Protection Systems (SPS) contained in the RAS/SPS-related Reliability Standards.

In FERC Order No. 693 (dated March 16, 2007), the Commission identified PRC-012-0, PRC-013-0, and PRC-014-0 as “fill-in-the-blank” standards and did not approve or remand them because they are applicable to the Regional Reliability Organizations (RROs), assigning the RROs the responsibility to establish regional procedures and databases, and to assess and document the operation, coordination, and compliance of RAS/SPS. The deference to regional practices precludes the consistent application of RAS/SPS-related Reliability Standard requirements. Although there is no FERC directive associated with Phase 3; this project will consider recommendations from the joint report*, Special Protection Systems (SPS) and Remedial Action Schemes (RAS): Assessment of Definition, Regional Practices, and Application of Related Standards,* issued by the System Analysis and Modeling Subcommittee (SAMS) and System Protection and Control Subcommittee (SPCS), as well as from the joint FERC-NERC inquiry of the September 2011 Southwest Blackout Event.

Standard(s) affected - PRC-012-1, PRC-013-1, PRC-014-1, PRC-015-1, PRC-016-1

Purpose / Industry Need

RAS/SPS are designed to detect predetermined System conditions and automatically take corrective actions to protect the reliability and integrity of the Bulk Electric System; consequently, the NERC Reliability Standards pertaining to these schemes should provide clear and unambiguous performance expectations and reliability benefits.

To accomplish this, the Phase 3 drafting team will correct the applicability of the fill-in-the-blank standards by assigning the requirement responsibilities to the specific users, owners, and operators of the Bulk-Power System; and will revise the RAS/SPS-related standards that address the:

- planning, coordination, and design of RAS/SPS,
- review, assessment, and documentation of RAS/SPS,
- analysis of RAS/SPS operation(s) and/or failure(s) to operate and corrective actions,
- testing of RAS/SPS, and maintenance of any non-protection system components used.

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft PRC-012-2 Clean **(71)** | Redline to Last Posted **(72)** Implementation Plan Clean **(73)** | Redline to Last Posted **(74)** Definition of Special Protection System Clean **(75)** | Redline to Last Posted **(76)**	Final Ballots Info **(85)** Vote	04/20/16 - 04/29/16	Summary **(86)** Ballot Results PRC-012-2 **(87)** Definition **(88)**	

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Clean (77) | Redline to Last Posted (78)

Supporting Materials

Mapping Document
Clean (79) | Redline to Last Posted (80)

VRF/VSL Justification
Clean (81) | Redline to Last Posted (82)

Q & A
Clean (83) | Redline to Last Posted (84)</td><td></td><td></td><td></td><td></td></tr>
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PRC-012-2
Clean (53) | Redline to Last Posted (54)

Implementation Plan
Clean (55) | Redline to Last Posted (56)

Supporting Materials

Unofficial Comment Form (Word) (57)

Mapping Document
Clean (58) | Redline to Last Posted (59)

VRF/VSL Justification
Clean (60) | Redline to Last Posted (61)

Q & A
Clean (62) | Redline to Last Posted (63)

Draft Reliability Standard Audit Worksheet (RSAW)</td><td>Additional Ballot and Non-binding Poll

Info (64)

Vote</td><td>03/09/16 - 03/18/16</td><td>Summary (66)

Ballot Results (67)

Non-binding Poll Results (68)</td><td></td></tr>
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Info (65)

Submit Comments</td><td>02/03/16 - 03/18/16</td><td>Comments Received (69)</td><td>Consideration of Comments (70)</td></tr>
<tr><td>Info

Send RSAW feedback to:

RSAWfeedback@nerc.net</td><td>02/17/16 - 03/18/16</td><td></td><td></td></tr>
</table>

Draft 2 PRC-012-2 Clean **(31)** | Redline to Last Posted **(32)** Proposed Definition of Special Protection System **(33)** Implementation Plan - PRC-012-2 Clean **(34)** | Redline to Last Posted **(35)** Implementation Plan – Definition **(36)** **Supporting Materials** Unofficial Comment Form (Word) **(37)** Mapping Document Clean **(38)** | Redline to Last Posted **(39)** VRF/VSL Justification Clean **(40)** | Redline to Last Posted **(41)** Q & A Clean **(42)** | Redline to Last Posted **(43)** Draft Reliability Standard Audit Worksheet (RSAW)	PRC-012-2 Additional Ballot and Non-binding Poll Definition Initial Ballot Updated Info **(44)** Info **(45)** Vote	12/30/15 - 01/08/16	Summary **(47)** Ballot Results PRC-012-2 **(48)** Definition **(49)** Non-binding Poll **(50)**	
	Comment Period Info **(46)** Submit Comments	11/25/15 - 01/08/16	Comments Received **(51)**	Consideration of Comments **(52)**
	Info Send RSAW feedback to: RSAWfeedback@nerc.net	12/09/15 - 01/08/16		
Draft 1 PRC-012-2 **(17)** Implementation Plan **(18)** **Supporting Materials** Unofficial Comment Form (Word) **(19)**	Initial Ballot and Non-binding Poll Updated Info **(23)** Info **(24)** Vote	09/25/15 - 10/05/15	Summary **(26)** Ballot Results **(27)** Non-binding Poll Results **(28)**	

Mapping Document **(20)** VRF/VSL Justification **(21)** Q & A **(22)** Draft RSAW	Comment Period Info **(25)** Submit Comments	08/20/15 - 10/05/15	Comments Received **(29)**	Consideration of Comments **(30)**
	Join Ballot Pools	08/20/15 - 09/18/15		
	Info Send RSAW feedback to: RSAWfeedback@nerc.net	09/03/15 - 10/05/15		
Draft 1 PRC-012-2 **(7)** **Supporting Materials** Unofficial Comment Form (Word) **(8)** SCPS Technical Report **(9)** PRC-012-1 **(10)** PRC-013-1 **(11)** PRC-014-1 **(12)** PRC-015-1 **(13)** PRC-016-1 **(14)**	Comment Period Info **(15)** Submit Comments	04/30/15 - 05/20/15	Comments Received **(16)**	

Project 2010-05.2 Phase 2 of Protection Systems Reference Material				
Standard Authorization Request (1) **Supporting Materials** Unofficial Comment Form (Word) **(2)** SPCS Technical Report **(3)** PRC Project Coordination Plan **(4)**	Comment Period Info **(5)** Submit Comments	02/18/14 - 03/19/14	Comments Received **(6)**	

Standards Authorization Request Form

When completed, email this form to:
Valerie.Agnew@nerc.net

For questions about this form or for assistance in completing the form, call Valerie Agnew at 404-446-2566.

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard			
Proposed Project Number and Name	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)		
Proposed Project Purpose:	Revise NERC Glossary of Terms definition: Special Protection System (SPS) Revise SPS-related Reliability Standards		
Date Submitted:	02/12/2014		
SAR Requester Information			
Name:	Al McMeekin		
Organization:	NERC		
Telephone:	404-446-9675	E-mail:	Al.McMeekin@nerc.net
SAR Type (Check as many as applicable)			
☐ New Standard ☒ Revision to existing Standard		☒ Withdrawal of existing Standard ☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The existing NERC Glossary of Terms definition for a Special Protection System (SPS) or, as used in the Western Interconnection, a Remedial Action Scheme (RAS), lacks the clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions, leading to inconsistent application of the related NERC Reliability Standards. In FERC Order No. 693 (dated March 16, 2007), the Commission identified three of the SPS-related standards (PRC-012-0, PRC-013-0, and PRC-014-0) as fill-in-the-blank standards because they are applicable to the Regional Reliability Organizations (RROs). Consequently, the Commission did not approve or remand them, rendering them neither mandatory nor enforceable. This project also addresses, in part, four recommendations related to identification and coordination of SPS from the joint FERC-NERC inquiry of the September 2011 Southwest Blackout Event. NOTE: Detailed information is included in the NERC Planning Committee report "Special Protection Systems (SPS) and Remedial Action Schemes (RAS): Assessment of Definition, Regional Practices, and Application of Related Standards" Revision 0.1 – April 2013.
Purpose or Goal (How does this request propose to address the problem described above?):
1) Establish a definition of an SPS that provides the specificity needed to consistently identify and classify protection schemes as SPS or RAS across all eight NERC Regions, thereby promoting the consistent application of the NERC Reliability Standards related to SPS. 2) Correct the applicability of the NERC Reliability Standards related to SPS by assigning responsibilities to the specific users, owners, and operators of the Bulk-Power System rather than the RROs. 3) Develop continent-wide standards to address all aspects of SPS, including but not limited to, the: • planning, coordination, and design of SPS, • review, assessment, and documentation of SPS, • operational considerations for monitoring, status notification, and response to failures, • analysis of SPS operations, and defining and reporting of SPS misoperations, • testing of SPS and maintenance of non-protection system components used in SPS.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
Successful implementation of a modified SPS definition and revised SPS standards will improve Bulk-

SAR Information

Power System reliability by providing continent-wide consistency in the identification and classification of SPS and the application of NERC Reliability Standards related to SPS.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

The project will develop a revised definition of SPS or RAS, as well as standards that address the:

- review of new or modified SPS,
- annual assessments of SPS in transmission planning studies,
- periodic comprehensive SPS assessments,
- analysis and reporting of SPS misoperations,
- maintenance, testing and operational aspects of SPS.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The SDT will revise the definition of SPS to provide the clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions.

The SDT will revise or retire the six existing SPS standards:

- PRC-012-0 Special Protection System Review Procedure
- PRC-013-0 Special Protection System Database
- PRC-014-0 Special Protection System Assessment
- PRC-015-0 Special Protection System data and Documentation
- PRC-016-0.1 Special Protection System Misoperations
- PRC-017-0 Special Protection System Maintenance and Testing

The SDT will correct the applicability in PRC-012-0, PRC-013-0, and PRC-014-0 by assigning the requirements to the specific users, owners, and operators of the bulk power system.

The SDT will combine appropriate requirements from PRC-012-0, PRC-013-0, PRC-014-0, and PRC-015-0 into a Reliability Standard The new standard will provide specific requirements for:

- review of new or modified SPS;
- annual assessments of SPS in transmission planning studies;
- periodic comprehensive SPS assessments;
- design of SPS; and

SAR Information
• coordination of SPS with other SPS, UFLS, UVLS, and Protection Systems. Due to the significant difference between Protection Systems and SPS, the subject of SPS misoperation is not addressed in the revision of Reliability Standard PRC-004. This SDT will develop a definition for SPS misoperation and revise PRC-016-0.1. The new Reliability Standard will provide specific requirements for the analysis of SPS operations and reporting of SPS misoperations. The SDT will address the complexity of maintaining and testing SPS, as well as the maintenance and testing of non-Protection System components used in SPS in a Reliability Standard. This SDT will coordinate with the PRC-005-4 SDT to prevent any overlaps or gaps in coverage. The SDT also will consider operational considerations for monitoring, status notification, and response to failures of SPS; and, if necessary, modify other related standards. The SDT will retire requirements that are administrative in nature that are not necessary for reliability of the Bulk-Power System, or that are superseded by other requirements; i.e., the new Reliability Standards will qualify as steady-state. No market interface impacts are anticipated.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.

Reliability Functions		
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems

Reliability and Market Interface Principles	
	reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards

Standard No.	Explanation
IRO-005-3.1a	The SDT may decide not to change this standard, but the SDT should keep the standard in mind since it contains potentially overlapping requirements.
PRC-001-1.1	The SDT may decide not to change this standard, but the SDT should keep the standard in mind since it contains potentially overlapping requirements.
PRC-005-2	The SDT may decide not to change this standard, or subsequently approved versions, but the SDT should keep the standard in mind to avoid any gaps or overlap between this standard and PRC-017-1.

Related Standards	
Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

Unofficial Comment Form

Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) – SAR

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard Authorization Request (SAR). The electronic comment form must be completed by **8 p.m. ET March 19, 2014**.

If you have questions please contact Al.McMeekin@nerc.net via email or by telephone at 404-446-9675.

The project page may be accessed by clicking here. (Please insert link to new project page)

Background Information

In early 2011, NERC staff decided to divide the approved project for Protection System Misoperations into two phases. Phase 1 of Project 2010-05 is addressing Misoperations of Protection Systems; the project began in April, 2011 and is ongoing. Project 2010-05.2 Special Protection Systems is Phase 2 of Protection Systems and will address all aspects of Special Protection Systems including misoperations of SPS. In FERC Order No. 693 (dated March 16, 2007), the Commission identified PRC-012-0, PRC-013-0, and PRC-014-0 as "fill-in-the-blank" standards and did not approve or remand them because they are applicable to the Regional Reliability Organizations (RROs); consequently, they are not mandatory or enforceable. This project proposes to correct the applicability by assigning responsibilities to the specific users, owners, and operators of the Bulk-Power System. The existing NERC Glossary of Terms definition for a Special Protection System (SPS) or Remedial Action Scheme (RAS), as used in the Western Interconnection, lacks the clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions. This leads to inconsistent application of the SPS-related Reliability Standards. At the request of the NERC Standards Committee, the Planning Committee directed the System Protection and Control Subcommittee (SPCS) to research this issue. The SPCS authored the attached report and provided a draft definition of SPS for consideration in the standards development process. This project proposes to establish a definition for SPS that provides the needed specificity to promote the consistent application of the NERC Reliability Standards related to SPS. This project also proposes to address, in part, four recommendations related to identification and coordination of SPS from the joint FERC-NERC inquiry of the September 2011 Southwest Blackout Event. There is no FERC directive associated with the SPS project: however, this project is being coordinated with Project 2008-02 UVLS, which does have an associated directive in P 1509 of Order No. 693 to modify PRC-010-0. These projects are linked because the proposed definition for Special Protection Systems must be written relative to the proposed definition of UVLS Program.

Questions
You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

1. Do you have any specific questions or comments relating to the scope of the proposed SAR?

   ☐ Yes
   ☐ No
   Comments:

2. If you are aware of the need for a regional variance or business practice that should be considered with this phase of the project, please identify it here.

   ☐ Yes
   ☐ No
   Comments:

3. If you have any other comments on this SAR that you haven't already mentioned, please provide them here:

   Comments:

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Special Protection Systems (SPS) and Remedial Action Schemes (RAS):

Assessment of Definition, Regional Practices, and Application of Related Standards

Revision 0.1 – April 2013

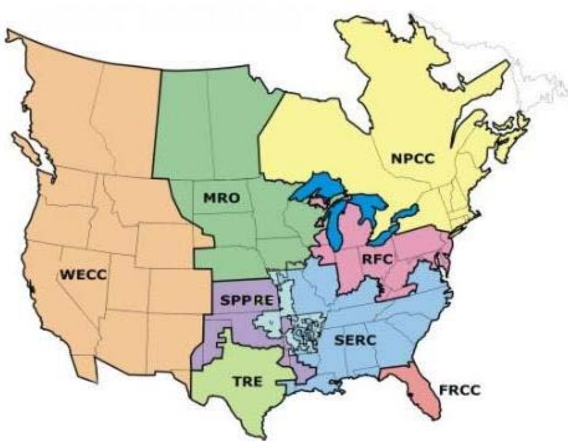
RELIABILITY | ACCOUNTABILITY

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to enhance the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a ten-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight Regional areas, as shown on the map and table below. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.



Note: The highlighted area between SPP RE and SERC denotes overlapping Regional area boundaries. For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.

NERC Regional Entities	
FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corporation
MRO Midwest Reliability Organization	**SPP RE** Southwest Power Pool Regional Entity
NPCC Northeast Power Coordinating Council	**TRE** Texas Reliability Entity
RFC ReliabilityFirst Corporation	**WECC** Western Electricity Coordinating Council

[1] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. NERC's reliability standards are also mandatory in Nova Scotia and British Columbia. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

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This technical document was approved by the NERC Planning Committee on March 5, 2013.

Executive Summary

The existing NERC Glossary of Terms definition for a Special Protection System (SPS or, as used in the Western Interconnection, a Remedial Action Scheme or RAS) lacks clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions, leading to inconsistent application of the related NERC Reliability Standards. In addition, three of the related standards (PRC-012-0, PRC-013-0, and PRC-014-0) were identified by FERC in Order No. 693 as fill-in-the-blank standards and consequently are not mandatory and enforceable.

NERC Standards Project 2010-05.2, Phase 2 of Protection Systems: SPS and RAS, will modify the current standards and definitions related to SPS and RAS. The NERC Standards Committee has identified that prior to initiating a project to address these issues, additional research is necessary to clearly define the problem and recommend solutions for consideration. A request for research was submitted by the Standards Committee on January 9, 2012 (see Appendix D). The Planning Committee had already approved a joint effort by the System Analysis and Modeling Subcommittee (SAMS) and System Protection and Control Subcommittee (SPCS) [2] on June 8, 2011 (see Appendix E) which includes issues identified in the request for research. This report addresses all issues identified in the scope of the joint SAMS and SPCS project as well as the Standards Committee request for research; upon approval by the Planning Committee the report should be forwarded to the Standards Committee to support Project 2010-05.2.

This report includes recommendations for a new definition of SPS and revisions to the six SPS-related PRC standards. A strawman definition is provided that eliminates ambiguity in the existing definition and identifies 13 types of schemes that are not SPS, but for which uncertainty has existed in the past based on experience within the Regions. The report also recommends that SPS should be classified based on the type of event to which the SPS responds and the consequence of misoperation. Classification of SPS facilitates standard requirements commensurate with potential reliability risk. Four classifications are proposed.

This report provides recommendations to address FERC concerns with PRC-012-0, PRC-013-0, and PRC-014-0, which assign requirements to Regional Reliability Organizations. Recommendations are made to reassign requirements to specific users, owners, and operators of the bulk power system to remedy this situation.

Project 2010-05.2 should consolidate the requirements pertaining to review, assessment, and documentation of SPS into one standard that includes continent-wide procedures for reviewing new or modified SPS, for assessing existing SPS in annual transmission planning assessments, and for periodic comprehensive SPS assessments. The project also should revise requirements pertaining to analysis and reporting of SPS misoperations in a revision of standard PRC-016-0.1. Due to the significant difference between protection systems and SPS, the subject of SPS misoperations should not be included in a future revision of PRC-004. Given the scope of work and need for drafting team members with different subject matter expertise it may be appropriate to sub-divide Project 2010-05.2 to address review, assessment and documentation of SPS separately from analysis and reporting of misoperations. This report also provides recommendations for Standards Committee consideration that are outside the scope of Project 2010-05.2. These additional recommendations pertain to maintenance and testing and operational aspects of SPS.

[2] The original scope of work involved the SPCS and the predecessor of SAMS, the Transmission Issues Subcommittee (TIS).

Introduction

Problem Statement

The existing NERC Glossary of Terms definition for a Special Protection System (SPS or, as used in the Western Interconnection, a Remedial Action Scheme or RAS) lacks clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions, leading to inconsistent application of the related NERC Reliability Standards. In addition, three of the related standards (PRC-012-0, PRC-013-0, and PRC-014-0) were identified by FERC in Order No. 693 as fill-in-the-blank standards and consequently are not mandatory and enforceable.

NERC Standards Project 2010-05.2, Phase 2 of Protection Systems: SPS and RAS, will modify the current standards and definitions related to SPS and RAS. The NERC Standards Committee has identified that prior to initiating a project to address these issues, additional research is necessary to clearly define the problem and recommend solutions for consideration.

Background

NERC Definitions

The existing NERC *Glossary of Terms* defines an SPS and RAS as:

> *Special Protection System (Remedial Action Scheme)*
>
> An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

In this document, use of the term SPS in general discussions and proposals for future definitions and standards apply to both SPS and RAS. Specific references to existing practices within Regions use the term SPS or RAS as appropriate for that Region.

The NERC *Glossary of Terms* defines a Protection System as:

> *Protection System*

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Inclusion of the words “protection system” in the term Special Protection System has raised questions whether this is an intentional reference such that SPS are a subset of Protection Systems. Use of protection system (lower case) within the SPS definition identifies that SPS are not Protection Systems. While SPS may include the same types of components as Protection Systems, SPS are not limited to detecting faults or abnormal conditions and tripping affected equipment. SPS may, for example, effect a change to the operating state of power system elements to preserve system stability or to avoid unacceptable voltages or overloads in response to system events. There are many reasons for implementing an SPS; for example, an SPS can be implemented to ensure compliance with the TPL Reliability Standards, to mitigate temporary operating conditions or abnormal configurations (e.g., during construction or maintenance activities), or in instances where system operators would not be able to respond quickly enough to avoid adverse system conditions.

A second area in which the existing SPS definition lacks clarity is the actions that are characteristics of SPS. The actions listed in the definition are broad and may unintentionally include equipment whose purpose is not expressly related to preserving system reliability in response to an event. Inclusion of any system taking “corrective action other than … isolation of faulted components to maintain system reliability” could be deemed to include equipment such as voltage regulators and switching controls for shunt reactive devices. This inclusion would then make these elements subject to single component failure considerations (sometimes referred to as redundancy considerations), coordination, reporting, and maintenance and testing requirements that may be required in the NERC Reliability Standards related to SPS.

This report proposes a revised definition of SPS to address these issues. Development of the proposed definition considered other definitions, common applications, and existing practices regarding classification of SPS.

NERC Reliability Standards

The NERC Reliability Standards contain six standards in the protection and control (PRC) series that specifically pertain to SPS.

- PRC-012-0: Special Protection System Review Procedure
- PRC-013-0: Special Protection System Database
- PRC-014-0: Special Protection System Assessment
- PRC-015-0: Special Protection System Data and Documentation
- PRC-016-0.1: Special Protection System Misoperations
- PRC-017-0: Special Protection System Maintenance and Testing

Three of these standards are not mandatory and enforceable because FERC identified them as fill-in-the-blank standards in Order No. 693, *Mandatory Reliability Standards for the Bulk-Power System*. These standards assign the Regional Reliability Organizations responsibility to establish regional procedures and databases, and to assess and document the operation, coordination, and compliance of SPS. The deference to regional practices, coupled with lack of clarity in the definition of SPS, preclude consistent application of requirements pertaining to SPS. This report provides recommendations that may be implemented through the NERC Reliability Standards Development Process to consolidate the standards and provide greater consistency and clarity regarding requirements.

Chapter 1 – SPS Definition

Considerations for a Revised Definition

Other Definitions in Industry

Several IEEE papers[3] define a similar term to SPS: System Integrity Protection System (SIPS). Adopting the SIPS definition is not appropriate because it is more inclusive than NERC's definition:

> "The SIPS encompasses special protection system (SPS), remedial action schemes (RAS), as well as other system integrity schemes, such as underfrequency (UF), undervoltage (UV), out-of-step (OOS), etc."[4]

NERC applies special consideration to UF and UV load shedding schemes in the Reliability Standards and considers OOS relaying in the context of traditional protection systems. Thus, SIPS is not an appropriate term for use in the Reliability Standards, and a new definition of SPS is more appropriate.

Common Application of SPS in Industry

Most SPS are used to address a range of system issues including stability, voltage, and loading concerns. Less common applications include arresting sub-synchronous resonance and suppressing torsional oscillations. Actions taken by SPS may include (but are not limited to): system reconfiguration, generation rejection or runback, load rejection or shedding, reactive power or braking resistor insertion, and runback or fast ramping of HVdc.

SPS are often deployed because the operational solutions they facilitate are substantially quicker and less expensive to implement than construction of transmission infrastructure. Permanent SPS have been implemented in some cases where the cost associated with system expansion is prohibitive, construction is not possible due to physical constraints, or obtaining permits is not feasible. In other cases temporary SPS have been implemented to maintain system reliability until transmission infrastructure is constructed; or when a reliability risk is temporary (e.g., during equipment outages) and the expense associated with permanent transmission upgrades is not justified.

The deployment of SPS adds complexity to power system operation and planning:

> "Although SPS deployment usually represents a less costly alternative than building new infrastructure, it carries with it unique operational elements among which are: (1) risks of failure on demand and of inadvertent activation; (2) risk of interacting with other SPS in unintended ways; (3) increased management, maintenance, coordination requirements, and analysis complexity."[5]

Subsequent sections of this report consider these three operational elements and provide recommendations regarding how they should be addressed in the NERC Reliability Standards. A summary of the number of schemes identified as SPS or RAS by Region is provided below.

Table 1: Overview of SPS by Region[6]

Region	Total Number	Region	Total Number
FRCC	20	SERC	20
MRO	36	SPP	6
NPCC	117	TRE	24
RFC	47	WECC	192

[3] One noteable reference, Madani, et al, "IEEE PSRC Report on Global Industry Experiences with System Integrity Protection Schemes (SIPS)," IEEE Trans. on Power Delivery, Vol. 25, Oct. 2010.
[4] *Ibid*.
[5] McCalley, et al, "System Protection Schemes: Limitations, Risks, and Management", PSERC Publication 10-19, Dec 2010.
[6] Numbers for 2011 obtained from data reported in the NERC Reliability Metric ALR6-1.

Classification of SPS Types

Three regions classify SPS according to various criteria, including the type of event the SPS is designed to address as well as the ability of the SPS to impact on a local versus wide-area reliability. The following information describes how NPCC, WECC and TRE classify SPS. Please note that examples of regional practices are provided for illustration throughout this document, but are not necessarily best practices or applicable to all Regions. Also in this context, what constitutes local versus wide-area varies among Regions and is not based on the NERC glossary term Wide Area, which is specific to calculation of Interconnection Reliability Operating Limits (IROL).[7]

NPCC

Type I – A Special Protection System which recognizes or anticipates abnormal system conditions resulting from design and operating criteria contingencies, and whose misoperation or failure to operate would have a significant adverse impact outside of the local area. The corrective action taken by the Special Protection System along with the actions taken by other protection systems are intended to return power system parameters to a stable and recoverable state.

Type II – A Special Protection System which recognizes or anticipates abnormal system conditions resulting from extreme contingencies or other extreme causes, and whose misoperation or failure to operate would have a significant adverse impact outside of the local area.

Type III – A Special Protection System whose misoperation or failure to operate results in no significant adverse impact outside the local area.

The following terms are also defined by NPCC to assess the impact of the SPS for their classification:

Significant adverse impact – With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from faults or disturbances, shall be deemed as having significant adverse impact:

a. system instability;
b. unacceptable system dynamic response or equipment tripping;
c. voltage levels in violation of applicable emergency limits;
d. loadings on transmission facilities in violation of applicable emergency limits;
e. unacceptable loss of load.

Local area – An electrically confined or radial portion of the system. The geographic size and number of system elements contained will vary based on system characteristics. A local area may be relatively large geographically with relatively few buses in a sparse system, or be relatively small geographically with a relatively large number of buses in a densely networked system.

WECC

Local Area Protection Scheme (LAPS): A Remedial Action Scheme (RAS) whose failure to operate would NOT result in any of the following:

- Violations of TPL-(001 thru 004)-WECC-1-CR – System Performance Criteria,
- Maximum load loss ≥ 300 MW,
- Maximum generation loss ≥ 1000 MW.

[7] The NERC Glossary defines Wide Area as "The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits."

Wide Area Protection Scheme (WAPS): A Remedial Action Scheme (RAS) whose failure to operate WOULD result in any of the following:

- Violations of TPL-(001 thru 004)-WECC-1-CR – System Performance Criteria,
- Maximum load loss ≥ 300 MW,
- Maximum generation loss ≥ 1000 MW.

Safety Net: A type of Remedial Action Scheme designed to remediate TPL-004-0 (System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)), or other extreme events.

TRE:

(a) A "Type 1 SPS" is any SPS that has wide-area impact and specifically includes any SPS that:

  (i) Is designed to alter generation output or otherwise constrain generation or imports over DC Ties; or

  (ii) Is designed to open 345 kV transmission lines or other lines that interconnect Transmission Service Providers (TSPs) and impact transfer limits.

(b) A "Type 2 SPS" is any SPS that has only local-area impact and involves only the facilities of the owner-TSP.

These three regional classifications can be roughly mapped:

- NPCC Type I = WECC WAPS = TRE Type 1
- NPCC Type III = WECC LAPS = TRE Type 2
- NPCC Type II = WECC Safety Net

SPS classification differentiates the reliability risk associated with SPS and provides a means to establish more or less stringent requirements consistent with the reliability risk. For example, it may be appropriate to establish less stringent requirements pertaining to monitoring or single component failure of SPS that present a lower reliability risk. A recommendation for classification of SPS is included with the proposed definition and subsequent discussion of standard requirements includes recommendations where different requirements based on classification are deemed appropriate.

Common Exclusions from the SPS Definition in Industry

Exclusions provide a means to assure that specific protection or control systems are not unintentionally included as SPS. The NERC glossary definition of SPS states that "An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS)."

Even with the exclusions in the NERC definition, other commonly applied protection and control systems meet the general language in the SPS definition. Considerable effort has been expended by industry discussing what systems are SPS. NPCC and SERC have documented examples of exclusions to the SPS definition in their regional guidelines. NPCC explicitly excludes "Automatic underfrequency load shedding; Automatic undervoltage load shedding and manual or automatic locally controlled shunt devices."[8] SERC's SPS guideline calls out specific exclusions as follows:

a. UFLS and/or UVLS,

b. Fault conditions that must be isolated including bus breakup / backup / breaker failure protection,

c. Relays that protect for specific equipment damage (such as overload, overcurrent, hotspot, reclose blocking, etc.),

d. Out of step relaying,

e. Capacitor bank / reactor controls,

[8] NPCC *Glossary of Terms Used by Directories*

f. Load Tap Changer (LTC) controls,

g. Automated actions that could be performed by an operator in a reasonable amount of time, including alternate source schemes, and

h. Scheme that trips generation to prevent islanding

A recommended list of protection and control systems that should be excluded from classification as SPS is included with the proposed definition.

Exclusion for Operator Aides

SAMS and SPCS considered a number of factors in discussing this subject including:

1) whether the actions are required to be completed with such urgency that it would be difficult for an operator to react and execute in the necessary time, and

2) whether the required actions are of such complexity or across such a large area that it would be difficult for an operator to perform the actions in the necessary time.

It is difficult to address these questions with concise and measurable terms, making it difficult to explicitly exclude them in the definition without introducing ambiguous terms counter to the objective of providing needed clarity in the SPS definition. Whether its existence is based upon convenience or not, any automated system with the potential to impact bulk power system reliability should be defined and expressed to the appropriate authority (e.g., Planning Coordinator, Reliability Coordinator) for the purposes of system modeling and coordination studies, to ensure that these systems are properly coordinated with other protection and control systems, and to ensure that inadvertent operations do not result in adverse system impacts.

On these bases, SAMS and SPCS decided not to provide an exclusion for schemes based on a general criterion as to whether the scheme automates actions that an operator could perform in a reasonable amount of time or schemes installed for operator convenience. However, SAMS and SPCS do recommend exclusions for specific applications that meet these criteria such as automatic sequences that are initiated manually by an operator. Furthermore, any scheme that is not installed "to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of two or more elements removed, an extreme event, or Cascading" would be excluded by definition, regardless of whether it is installed to assist an operator.

Voltage Threshold

All elements, at any voltage level, of an SPS intended to remediate performance issues on the bulk electric system (BES), or of an SPS that acts upon BES elements, should be subject to the NERC requirements.

Proposed Definition

The proposed definition clarifies the areas that have been interpreted differently between individual entities and within Regions, in some cases leading to differing regional definitions of SPS. The proposed definition provides a framework for differentiating among SPS with differing levels of reliability risk and will support the drafting of new or revised SPS standards.

Special Protection System (SPS)

A scheme designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of faulted elements, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading.

Subject to the exclusions below, such schemes are designed to maintain system stability, acceptable system voltages, acceptable power flows, or to address other reliability concerns. They may execute actions that include but are not limited to: changes in MW and Mvar output, tripping of generators and other sources, load curtailment or tripping, or system reconfiguration.

The following schemes do not constitute an SPS in and of themselves:

a) Underfrequency or undervoltage load shedding

b) Locally sensing devices applied on an element to protect it against equipment damage for non-fault conditions by tripping or modifying the operation of that element, such as, but not limited to, generator loss-of-field or transformer top-oil temperature

c) Autoreclosing schemes

d) Locally sensed and locally operated series and shunt reactive devices, FACTS devices, phase-shifting transformers, variable frequency transformers, generation excitation systems, and tap-changing transformers

e) Schemes that prevent high line voltage by automatically switching the affected line

f) Schemes that automatically de-energize a line for non-fault operation when one end of the line is open

g) Out-of-step relaying

h) Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)

i) Protection schemes that operate local breakers other than those on the faulted circuit to facilitate fault clearing, such as, but not limited to, opening a circuit breaker to remove infeed so protection at a remote terminal can detect a fault or to reduce fault duty

j) Automatic sequences that proceed when manually initiated solely by an operator

k) Sub-synchronous resonance (SSR) protection schemes

l) Modulation of HVdc or SVC via supplementary controls such as angle damping or frequency damping applied to damp local or inter-area oscillations

m) A Protection System that includes multiple elements within its zone of protection, or that isolates more than the faulted element because an interrupting device is not provided between the faulted element and one or more other elements

SPS are categorized into four distinct types. These types may be subject to different requirements within the NERC Reliability Standards.

- Type PS (planning-significant): A scheme designed to meet system performance requirements identified in the NERC Reliability Standards, where failure or inadvertent operation of the scheme can have a significant impact on the BES.
- Type PL (planning-limited): A scheme designed to meet system performance requirements identified in the NERC Reliability Standards, where failure or inadvertent operation of the scheme can have only a limited impact on the BES.
- Type ES (extreme-significant): A scheme designed to limit the impact of two or more elements removed, an extreme event, or Cascading, where failure or inadvertent operation of the scheme can have a significant impact on the BES.
- Type EL (extreme-limited): A scheme designed to limit the impact of two or more elements removed, an extreme event, or Cascading, where failure or inadvertent operation of the scheme can have only a limited impact on the BES.

An SPS is classified as having a significant impact on the BES if failure or inadvertent operation of the scheme results in any of the following:

- Non-Consequential Load Loss ≥ 300 MW

- Aggregate resource loss (tripping or runback of generation or HVdc) > the largest Real Power resource within the interconnection[9]
- Loss of synchronism between two or more portions of the system each including more than one generating plant
- Negatively damped oscillations

If none of these criteria are met, the SPS is classified as having a limited impact on the BES.

Definition of Significant and Limited Impact

The parameters used to define the bright line between "significant" and "limited" impacts are proposed to consider only the electrical scale of the event. Defining the bright line in this way eliminates the difficulty in distinguishing the geographic impact of an SPS as either "wide" or "local."

NERC Standard EOP-004-1, DOE Form OE-417 Electric Emergency Incident and Disturbance Report, establishes the criteria by which an event is categorized as a Disturbance and requires a disturbance report. In terms of SPS, the proposed criteria for significant impact mirrors EOP-004-1 by including a non-consequential load loss value of 300 MW.

NERC Reliability Standards require consideration of loss of any generating unit; therefore, generating unit loss would not impact reliability of the bulk power system unless the combined capacity loss exceeds the largest unit within the interconnection. The generation loss level was selected as a loss greater than the largest unit within an interconnection on this basis.

Tripping multiple generating units exceeding the capacity of the largest unit within an interconnection, system separation (loss of synchronism) that results in isolation of a portion of an interconnection, or system oscillations that increase in magnitude (negatively-damped) are indicators of adverse impact to the reliability of an interconnection. These criteria identify system performance indicative of the potential for instability, uncontrolled separation, or cascading outages, without requiring detailed analyses to confirm the extent to which instability, uncontrolled separation, or cascading outages may occur. These indicators, combined with the loss of load criterion, are proposed to identify the potential reliability risk associated with failure of a SPS. Subsequent sections of this report recommend requirements for assessment and design of SPS based on whether the potential reliability risk associated with the SPS are significant versus limited impacts.

The proposed thresholds differentiate between significant and limited impact. While it should be clear there is no upper threshold on what constitutes a significant impact, there also is no lower threshold proposed as to what constitutes limited impact. Whether a scheme is an SPS is determined by the definition; significant and limited impact are used only to classify SPS. For example, if a scheme is installed to meet system performance requirements identified in the NERC Reliability Standards then it is an SPS regardless of its potential impact. A failure of the SPS would result in a violation of a NERC Reliability Standard. Thus, excluding a scheme with impact below a certain threshold would undermine the reliability objective of the standard requirement the scheme is installed to address.

[9] I.e., Eastern, Western, ERCOT, or Quebec Interconnection.

Chapter 2 – Design and Maintenance Requirements

Under the proposed definition, SPS are implemented to preserve acceptable system performance, and as such may be critical to power system reliability and therefore subject to single component failure considerations, and maintenance and testing requirements outlined in the PRC standards.

General Design Considerations

Aside from the single component failure, and maintenance and testing considerations outlined below, Disturbance Monitoring Equipment should be provided in the design of an SPS to permit analysis of the SPS performance following an event. Also, as with other automated systems, the design of an SPS should facilitate its maintenance and testing.

SPS Single Component Failure Requirements

Requirement R1.3 in PRC-012-0 requires SPS owners to demonstrate an SPS is designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in NERC Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0. This requirement should be retained in future standards such that Types PS and PL SPS are required to be designed so that power system performance meets the performance requirements of TPL-001-0, TPL-002-0, or TPL-003-0, in the event of a single component failure. The design of Type PS and PL SPS can provide the required performance through any of the methods outlined below, or a combination of these methods:

1. Arming more load or generation than necessary to meet the intended results. Thus the failure of the scheme to drop a portion of load or generation would not be an issue. In this context it is necessary to arm the tripping of more load delivery points or generating units rather than simply arming more MW of load or generation. When this option is used, studies of the SPS design must demonstrate that tripping the total armed amount of load or generation will not cause other adverse impacts to reliability.

2. Providing redundancy of SPS components listed below.

   - Any single ac current source and/or related input to the SPS. Separate secondary windings of a free-standing current transformer (CT) or multiple CTs on a common bushing should be considered an acceptable level of redundancy.
   - Any single ac voltage source and/or related input to the SPS. Separate secondary windings of a common capacitance coupled voltage transformer (CCVT), voltage transformer (VT), or similar device should be considered an acceptable level of redundancy.
   - Any single device used to measure electrical quantities used by the SPS.
   - Any single communication channel and/or any single piece of related communication equipment used by the SPS.
   - Any single computer or programmable logic device used to analyze information and provide SPS operational output.
   - Any single element of the dc control circuitry that is used for the SPS, including breaker closing circuits.
   - Any single auxiliary relay or auxiliary device used by the SPS.
   - Any single breaker trip coil for any breaker operated by the SPS.
   - Any single station battery or single charger, or other single dc source, where central monitoring is not provided for both low voltage and battery open conditions.

3. Using remote or time delayed actions such as breaker failure protection[10] or alternative automatic actions to back up failures of single components (e.g., an independent scheme that trips an element if an overload exists for longer than the time necessary for the SPS to take action). The backup operation would still need to provide mitigation to meet the necessary result in the required timeframe.

4. For Type PL SPS, manual backup operation may be used to address the failure of a single SPS component if studies are provided to show that implemented procedures will be effective in providing the required response when a SPS failure occurs. The implemented procedures will include alarm response and manual operation time requirements to provide the backup functions.

Some SPS utilize an Energy Management System (EMS) system for transmitting signals or calculating information necessary for SPS operation such as the amount of load or generation to trip. Loss of the EMS system must be considered when assessing the impact of a single component failure. For example, when the EMS is used to transmit a signal, a separate communication path must be available. When a non-redundant EMS provides a calculated value to two otherwise independent systems, a backup calculation or default value must be provided to the SPS in the event of an EMS failure.

Types ES and EL SPS are designed to provide system protection against extreme events. The events that Types ES and EL SPS are intended to address have a lower probability of occurrence and the TPL standards do not require mitigation for these events. Dependability of SPS operation is therefore not critical for these events and, consistent with the existing standards, these SPS should not be required to perform their protection functions even with a single component failure. Design requirements for Type ES SPS should emphasize security; however, in some cases Type ES SPS are installed to address an event with consequences so significant (e.g., system separation or collapse of an interconnection) that consideration should be given to both dependability and security. In consideration that the addition of redundancy in some cases might make the SPS less secure, such cases may warrant implementation of a voting scheme[11].

Maintenance and Testing

The Project 2007-17, Protection System Maintenance and Testing, drafting team revised PRC-005 to include maintenance and testing requirements for SPS contained in PRC-017-0.[12] All of the existing requirements in PRC-017-0 that are based on a reliability objective are mapped to PRC-005-2. However, this report identifies two subjects that are not covered in either the existing standard or the proposed standard:

- Complex SPS require different procedures than those used for maintenance of protection systems.
- Maintenance of non-protection system components used in SPS is not addressed in any existing NERC Reliability Standards.

These subjects should be addressed in a future revision of PRC-005 or development of a separate standard.

[10] In this context it is not intended that breaker failure protection must be redundant; rather, that breaker failure protection may be relied on to meet the design requirements (e.g., if an SPS required tripping a breaker with a single trip coil).
[11] A voting scheme achieves both dependable and secure operation by requiring, for example, two out of three schemes to detect the condition prior to initiating action.
[12] PRC-005-2 was adopted by the NERC Board of Trustees on November 7, 2012

Chapter 3 – Study and Documentation Requirements

Review and Approval of New or Modified SPS

Requirement R1 in PRC-012-0 requires each Regional Reliability Organization to have a documented review procedure to ensure that SPS comply with regional criteria and NERC Reliability Standards. However, the potential for SPS interaction and for SPS operation or misoperation to have inter-regional impacts suggests that a uniform procedure for reviewing SPS is important to ensure bulk power system reliability. This report recommends fundamental aspects that should be included in a continent-wide SPS review procedure and included in the revised reliability standards pertaining to SPS. The review process should be conducted by an entity or entities with the widest possible view of system reliability, and must be a user, owner, or operator of the bulk power system. To assure that both planning and operating views are evaluated before a new or modified SPS is placed in service, responsibility for reviewing and approving implementation of SPS should be assigned to the Reliability Coordinator and Planning Coordinator. Ideally these reviews should be performed on a regional or interconnection-wide basis. If in the future an entity is registered as the Reliability Assurer for each Region, the responsibility for performing these reviews, or alternately for coordinating these reviews, should be assigned to the Reliability Assurer.

A continent-wide review process should be established in a revised reliability standard that includes the following aspects:

- The SPS owner[13] should be required to obtain approval from its Reliability Coordinator and its Planning Coordinator in whose area the SPS is installed[14] prior to placing a new or modified SPS in service.
- An entity proposing a new or modified SPS should be required to file an application with its Reliability Coordinator and Planning Coordinator that includes the following information:
    - A document outlining the details of the SPS as specified below in the section titled, Data Submittals by Entities that Own SPS.
    - Studies that demonstrate the operation, coordination, and effectiveness of the SPS, including the impacts of correct operation, a failure to operate, and inadvertent operation. The study report should include the following:[15]
        - Entity conducting the SPS study
        - Study completion date
        - Study years
        - System conditions
        - Contingencies analyzed
        - Demonstration that the SPS meets criteria discussed in the Design Considerations chapter of this report
        - Discussion of coordination of the SPS with other SPS, UFLS, UVLS, and protection systems
- The Reliability Coordinator and Planning Coordinator should be required to provide copies of the application and supporting information to Transmission Planners, Transmission Operators, and Balancing Authorities within their area, and to adjacent Reliability Coordinators and Planning Coordinators.
- Entities receiving the application should be allowed to provide comments to the Reliability Coordinator and Planning Coordinator.

[13] In cases where more than one entity owns an SPS, the standards should designate that a designated "reporting entity" be responsible for transmitting data to the Reliability Coordinator and Planning Coordinator, while all owners retain responsibility for other requirements such as maintenance and testing.

[14] In cases where an SPS has components installed in or takes action in more than one Reliability Coordinator area or Planning Coordinator area, all affected Reliability Coordinators and Planning Coordinators should have approval authority.

[15] The same documentation requirements should apply to Periodic Comprehensive Assessments of SPS Coordination.

- When deciding whether to approve an SPS, the Reliability Coordinator and the Planning Coordinator in whose area the SPS is to be installed or modified should be required to consider supporting information provided with the application; comments from Transmission Planners, Transmission Operators, and Balancing Authorities and other Reliability Coordinators and Planning Coordinators; and any supplemental information provided by the SPS owner.
- The basis of the Reliability Coordinator and Planning Coordinator approval should be limited to whether all required information has been submitted and the studies are sufficient to support that all performance requirements are met.

Assessment of Existing SPS

Study of SPS in Annual Transmission Planning Assessments

Requirement R1 in PRC-014-0 specifically addresses assessment of the operation, coordination, and effectiveness of all SPS and assigns this responsibility to the Regional Reliability Organization. Reliability standards must assign responsibility to owners, operators, and users of the bulk power system. For assessments of SPS, it is important to identify an entity with the necessary expertise in system studies and a wide-area view to facilitate coordination of SPS across the system. Instead of assigning this responsibility to the Regional Reliability Organization or the Regional Entity, the assessment responsibility should be assigned to the Planning Coordinator and Transmission Planner for SPS within their specific area.

Annually, the Planning Coordinator and Transmission Planner should review the operation, coordination, and effectiveness of the SPS, including the impacts of correct operation, a failure to operate, and inadvertent operation. If system changes have occurred which can affect the operation of the SPS, annual studies should include system conditions and contingencies modeled in the study supporting the application for installation of or modifications to an SPS.

Any issues identified should be documented and submitted to the Reliability Coordinator and the SPS owner. The Reliability Coordinator and Planning Coordinator should be required to determine, in consultation with the SPS owner, whether a corrective action plan is required, and if so, whether the SPS can remain in-service or must be removed from service until a corrective action plan is implemented. If a corrective action plan is required, the SPS owner should be required to submit an application for a modified SPS as described above in the section titled Review and Approval of New or Modified SPS.

Periodic Comprehensive Assessments of SPS Coordination

Comprehensive assessment should occur every five years, or sooner, if significant changes are made to system topology or operating characteristics that may impact the coordination among SPS and between SPS and UFLS, UVLS, and other protection systems. Responsibility for the comprehensive assessment should be assigned to the Reliability Coordinator to achieve the wide-area review necessary for a comprehensive assessment. Planning Coordinators, Transmission Planners, Transmission Operators, Balancing Authorities, and adjacent Reliability Coordinators should be required to provide support to the Reliability Coordinator when requested to do so. As part of the periodic review the Reliability Coordinator should be required to request the Planning Coordinator and Transmission Planner to assess and document whether the SPS is still necessary, serves its intended purpose, meets criteria discussed in the Design Considerations chapter of this report, coordinates with other SPS, UFLS, UVLS, and protection systems, and does not have unintended adverse consequences on reliability.

The Reliability Coordinator should be required to provide its periodic assessment to Planning Coordinators, Transmission Planners, Transmission Operators, and Balancing Authorities in its area, and to adjacent Reliability Coordinators, and should be required to consider comments provided by these entities. Any issues identified with an SPS should be documented and submitted to the SPS owner. If any concerns are identified, the Reliability Coordinator and the Planning Coordinator in whose area the SPS is installed should determine, in consultation with the SPS owner, whether a corrective action plan is required, and if so, whether the SPS can remain in-service or must be removed from service until a corrective action plan is implemented. If a corrective action plan is required, the SPS owner should be required to submit an application for a modified SPS as described above in the section titled Review and Approval of New or Modified SPS.

Documentation Requirements

Data Submittals by Entities that Own SPS

Reliability standard PRC-015-0 establishes requirements for SPS owners to provide data for existing and proposed SPS as specified in reliability standard PRC-013-0 Requirement R1. PRC-013-0 establishes the data provided shall include the following:

- Design Objectives — Contingencies and system conditions for which the SPS was designed
- Operation — The actions taken by the SPS in response to Disturbance conditions
- Modeling — Information on detection logic or relay settings that control operation of the SPS

This requirement should be carried forward to the revised standards for the SPS owner to provide detailed information regarding the conditions of SPS operation. However, this requirement should be modified to ensure that communication of this information is clear and understandable to all entities that require the information to plan and operate the bulk power system (e.g., Planning Coordinators, Transmission Planners, Reliability Coordinators, Transmission Operators, and Balancing Authorities). Additional specificity should be added to this list of data to assure that sufficient information is provided for entities to understand and model SPS operation.

Since SPS design and complexity vary considerably, a brief description of the action taken when certain system conditions are detected generally does not provide a sufficient level of detail. Conversely, logic and control wiring diagrams may provide too much detail that is not readily understood except by the SPS owner's protection and control engineers. To achieve an appropriate level of detail that provides a common understanding by the SPS owner and other entities, the SPS owner should work with the Transmission Planner to develop a document outlining the details of the SPS operation specifically tailored to the needs and knowledge level of the entities that require this information to plan and operate the bulk power system. The document should include the following:

- SPS name
- SPS owner
- Expected in-service date
- Whether the SPS is intended to be permanent or temporary
- SPS classification (per revised definition), and documentation or explanation of how the SPS mitigates the planning or extreme event and why the impact is significant or limited
- Logic diagram, flow chart, or truth table documenting the scheme logic and illustrating how functional operation is accomplished
- Whether the SPS logic is:
    - Event-based [16]
    - Parameter-based [17]
    - A combination of event-based and parameter-based
- System performance criteria violation necessitating the SPS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery)

[16] Event-based schemes directly detect outages and/or fault events and initiate actions such as generator/load tripping to fully or partially mitigate the event impact. This open-loop type of control is commonly used for preventing system instabilities when necessary remedial actions need to be applied as quickly as possible.

[17] Parameter-based schemes measure variables for which a significant change confirms the occurrence of a critical event. This is also a form of open-loop control but with indirect event detection. The indirect method is mainly used to detect remote switching of breakers (e.g., at the opposite end of a line) and significant sudden changes which can cause instabilities, but may not be readily detected directly. To provide timely remedial action execution, the measured variables may include power, angles, etc., and/or their derivatives.

- Parameters and equipment status monitored as inputs to the SPS (e.g., voltage, current or power flow, breaker position) and specific monitoring points and locations
- Under what conditions the SPS is armed (e.g., always armed, armed for certain system conditions, actuation thresholds)
- Whether arming is accomplished automatically or manually, if required
- Arming criteria – analog quantities and/or equipment status monitored to determine existence of the system condition for which SPS is armed (e.g., generation/load patterns, reactive power reserves, facility loading)
- Action taken – for example: transmission facilities switched in or out; generators tripped, runback, or started; load dropped; tap setting changed (phase-shifting transformer); controller set-point changed (AVR, SVC, HVdc converter); turbine fast valving or generator excitation forcing; braking resistor insertion
- Time to operate, including intentional time delays (e.g., timer settings) and inherent delays (e.g., relay operating time)
- Information with sufficient detail necessary to model the SPS.

SPS Database

PRC-013-0, Requirement R1 requires the Regional Reliability Organization to maintain an SPS database, including data on design objectives, operation, and modeling of each SPS. Similar to the other requirements presently assigned to the Regional Reliability Organization, this requirement should be assigned to a user, owner, or operator of the bulk power system. To minimize the number of databases and facilitate sharing of information with entities that require SPS data to plan and operate the bulk power system, this requirement should be assigned to the Planning Coordinator. The Planning Coordinator should be required to provide its database to NERC for the purpose maintaining a continent-wide data base[18] that NERC would make available to Reliability Coordinators, Transmission Operators, Balancing Authorities, Planning Coordinators, and Transmission Planners that require this data. The database should contain information for each SPS as described above in the section titled, Data Submittals by Entities that Own SPS.

[18] The requirement in a NERC Reliability Standard would be applicable to the Planning Coordinator; the responsibility for NERC to maintain a continent-wide database should be addressed outside the standard.

Chapter 4 – Operational Requirements

Due to their unique nature, SPS may have special operational considerations, with potentially differing requirements among the proposed types for monitoring, notification of status, and the response time required to address SPS failure. Furthermore, consideration should be given to the documentation of procedures for operator interaction with SPS, and how operators should respond to SPS failures.

One entity should be assigned primary responsibility for monitoring, coordination, and control of an SPS. Depending on the complexity, this responsible party may be a Reliability Coordinator, Balancing Authority, or Transmission Operator. Complex SPS may have multiple owners or affected entities, including different functional entities and the chain of notification and control should be clearly established.

Monitoring of Status

Existing NERC Reliability Standard IRO-005-3.1a, Requirement R1.1 requires Reliability Coordinators to monitor SPS. Similarly PRC-001-1, Requirement R6 requires Balancing Authorities and Transmission Operators to monitor SPS. The SPS standards should establish the level of monitoring capability that must be provided by the SPS owner. Classification of the SPS will dictate its design criteria and may lend itself to different levels of monitoring.

All SPS should be monitored by SCADA/EMS with real-time status communicated to EMS that minimally includes whether the scheme is in-service or out-of-service, and the current operational state of the scheme. For SPS that are armed manually the arming status may be the same as whether the SPS is in-service or out-of-service. For SPS that are armed automatically these two states are independent because an SPS that has been placed in-service may be armed or unarmed based on whether the automatic arming criteria have been met. In cases where the classification of the SPS requires redundancy, the minimal status indications should be provided for each system. The minimum status is sufficient for operational purposes; however, where possible it may be useful to provide additional information regarding partial failures or the status of critical components to allow the SPS owner to more efficiently troubleshoot a reported failure. Whether this capability exists will depend in part on the design and vintage of equipment used in the SPS. While all schemes should be required to provide the minimum level of monitoring, new schemes should be designed with the objective of providing monitoring similar to what is provided for microprocessor-based protection systems.

Similarly, the SCADA/EMS presentation to the operator would need to indicate the criticality of the scheme (e.g., through the use of audible alarms and a high priority in the alarm queue). The operator would be expected to know how to respond depending on the nature of the issue detected, as some partial SPS failures might not result in a complete failure of the scheme.

In cases where SPS cross ownership and operational boundaries, it is important that all entities involved with the SPS are provided with an appropriate level of monitoring.

Notification of Status

Since the owner and operator of an SPS or component are often different organizations, and because SPS may cross entity boundaries, it is important that the SPS status is communicated appropriately between entities. Existing NERC Reliability Standards already require some level of notification of SPS status by Reliability Coordinators, Balancing Authorities and Transmission Operators.[19] Furthermore, SPS owners (e.g., Transmission Owner, Generator Owner) should be responsible for communicating scheme or component issues to the operating organizations (e.g., Transmission Operator, Generator Operator), who should then be responsible for communicating the issues to the involved Reliability Coordinator, Balancing Authority, and other Transmission Operators or Generator Operators that might rely on the SPS (for example, in setting operating limits).

The required timing associated with such notification will depend on the type of scheme; for example, the misoperation of a Type PS or ES scheme would require rapid notification to all interested parties. In general, the more critical a scheme is to the reliability of the system, the then more important its notification and response; however, it is also important that some

[19] See, for example, IRO-005-3.1a Requirement R9 and PRC-001-1, Requirement R6.

level notification be made for all schemes, due to the complex nature of SPS and their interaction with each other, to allow entities to understand the reliability impact of a neighboring entity's SPS failure or misoperation.

Response to Failures

As with many of the other issues, the response time required to address SPS failure is tightly coupled to the potential impact of the SPS as well as the operating conditions at the time of failure. For example, if the SPS is intended to address an event with a significant impact such as an IROL, then any corrective action in response to a misoperation would need to be taken in 30 minutes or less, consistent with the T_V[20] associated with the IROL. On the other hand, depending on the operating conditions, a particular scheme's unavailability may not result in an adverse impact to reliability. Actions taken following an SPS failure should consider whether the failure affects dependability or security of the SPS and the potential impact to reliability.

Generally speaking, the SPS failure modes are known and the necessary corrective actions are documented (e.g., contingency plans) so that the system can be placed in a safe operating state. In any case, a full or partial failure of an SPS requires that the system performance level provided by having the SPS in service is met, or a more conservative and safe operating condition would need to be achieved, in a timeframe appropriate for the nature of the SPS and operating conditions. When one system of a redundant SPS fails, the action taken by the operator may depend on the system conditions the SPS is installed to address and the operating conditions at the time of the failure. For example, an operator may respond to failure of one system by operating to higher equipment ratings when an SPS is installed to address thermal loading violations. However, the operator may not be able to rely on the remaining system of a redundant SPS when the SPS is installed to prevent instability, system separation, or cascading outages, in which case the operator must reduce transfers or take other actions to secure the system.

Operational Documentation

Operational documentation is necessary to provide the operator with enough information to understand all aspects of the scheme and is used to provide knowledge transfer as staff changes occur. Overall documentation requirements are identified in the section on Study and Documentation Requirements; however, the operator does not require all information provided by the SPS owner for the database maintained by the Planning Coordinator. The operational documentation is sometimes called a "description of operations" and provides the operation actions for the following areas:

- General Description – This provides an overview of the purpose of the scheme including the monitoring, set points and actions of the scheme. The operator and other stake holders can use this information to understand the need for the scheme.
- Operation – This will provide the specific information concerning, arming, alarming, and actions taken by this scheme including the monitoring points of the scheme. The operator can use this information to provide triage and plan a course of action concerning restoration of the electric system. This information should provide an understanding of what has operated, why these elements have been impacted, and possible mitigations or restoration activities.
- Failures, Alarms, Targeting – This information will provide the operator and first responders with descriptions of alarms and targets and the actions needed when the scheme is rendered unusable either during maintenance or because of a failure. The instructions will guide the operator on how to respond to component failures that partially impair the scheme or those failures that might disable entire scheme.

Regulatory agencies provide oversight of these schemes and require owners of these schemes to provide descriptions and operational information. NERC PRC-015 requires owners to provide description of schemes and the Study and Documentation Requirements section of this report proposes specific documentation requirements for inclusion in a revised standard. In addition to NERC, some Regional Entities also require SPS owners to provide the Region with additional information concerning the operations of the schemes. Some regional regulatory agencies also require the owners to verify that they have taken certain actions after a misoperation or a failure of these schemes.

[20] Specifically, T_V is discussed in NERC Reliability Standard IRO-009-1, Requirement R2.

Chapter 5 – Analysis of SPS Operations

Operations of SPS provide an opportunity to assess their performance in actual operating power systems, as opposed to assessing the impact through a preconceived set of system studies. Analysis of SPS operations is presently addressed in PRC-012-0 and PRC-016-0.1, which establish requirements for Regional Reliability Organizations and SPS owners respectively. PRC-012-0 requires that each Regional Reliability Organization establish a regional definition of an SPS misoperation (R1.6), as well as requirements for analysis and documentation of corrective action plans for all SPS misoperations (R1.7). PRC-016-0.1 requires that SPS owners analyze their SPS operations and maintain a record of all misoperations in accordance with their regional SPS review procedure (R1) and that SPS owners take corrective actions to avoid future misoperations (R2).

PRC-012-0 is one of the standards identified in FERC Order No. 693 as a fill-in-the-blank standard and this standard therefore is not mandatory and enforceable. SAMS and SPCS have not identified any rationale for having regional definitions of an SPS misoperation or regional processes for analyzing SPS operations. Establishment of a continent-wide definition and review process will facilitate meaningful metrics for assessing the impact of SPS misoperations on bulk power system reliability. Rather than revising PRC-012-0 to assign responsibility for developing regional definitions and review processes to a user, owner, or operator of the bulk power system, this report recommends that one continent-wide definition and review process should be established through the NERC Reliability Standard Development Process, and that criteria be established for SPS owners to follow a continent-wide review process in place of the existing requirements in PRC-016-0.1.

SPS Misoperation Definition

Establishing a definition of an SPS misoperation must account for the many different aspects affecting whether operation of an SPS achieves its desired effect on power system performance. In addition to aspects traditionally considered in assessing protection system misoperations such as failure to operate and unnecessary operation, analysis of an SPS operation also must consider whether the action was properly initiated and whether the initiated action achieved the desired power system performance. This report proposes that a tiered definition be used to assess which aspects of an SPS operation are reportable for metric purposes, which require analysis and reporting to the Reliability Coordinator and Planning Coordinator, and which require a corrective action plan. The following definition is recommended for an SPS misoperation.

SPS Misoperation

A SPS Misoperation includes any operation that exhibits one or more of the following attributes:

a. 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 occur.

b. Unnecessary Operation – Any operation of a SPS that occurs without the occurrence of the intended system trigger condition(s).

c. Unintended System Response – Any unintended adverse system response to the SPS operation.

d. Failure to Mitigate – Any failure of the SPS to mitigate the power system conditions for which it is intended.

The SPS review process should include requirements based on the SPS misoperation definition as follows:

- The SPS owner must provide analysis of all misoperations to its Reliability Coordinator and Planning Coordinator.
- The SPS owner must develop and implement a corrective action plan for all SPS misoperations.
- Reporting for reliability metric purposes should be limited to SPS misoperations that exhibit attributes (a) or (b) of the proposed definition, but should be addressed outside PRC-016-1, in a manner similar to the process under development for reporting protection system misoperations in Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

SPS Operation Review Process

The review process should be included in a revised version of PRC-016 and PRC-012-0 should be retired upon approval of a continent-wide definition and revised PRC-016. The SPS operation review process should require that SPS owners analyze all SPS operations in sufficient detail to determine whether or not the response of the power system to the SPS operation is appropriate to meeting the purpose of the SPS. This requirement should be applied uniformly to all SPS types. The time required to review each SPS operation will vary with the complexity of the SPS.

The analysis of each operation should include:

- The power system conditions which triggered the SPS.
- A determination of whether or not the SPS responded as designed.
- An analysis of the power system response to the SPS operation.
- An analysis of the effectiveness of the SPS in mitigating power system issues it was designed to address. This analysis should identify whether or not those issues existed or were likely to occur at the time of the SPS operation.
- Any unintended or adverse power system response to the SPS operation.

For each SPS operation, the analysis should identify the power system conditions which existed at the time of the SPS operation. These conditions should be analyzed to determine whether or not the SPS operation was appropriate. This part of the analysis is to determine both whether or not the SPS operated as designed, and whether or not the conditions the SPS is intended to mitigate were present at the time of SPS operation.

Some SPS use a proxy to determine the possible existence of a system problem. For example, the opening of a generator outlet may cause an overload remote from the generator. An SPS could monitor the status of the outlet and run back generation to avoid the possible overload, rather than monitoring the loading on the potentially impacted element. The analysis should determine whether the SPS responded to the loss of outlet, and whether the overload actually would have occurred without SPS operation.

The analysis should also examine the response of the system to the SPS operation. This part of the analysis is to determine whether or not the SPS is effective in its intended mitigation, and if it has unforeseen adverse or unnecessary impacts on the power system.

As noted with the proposed definition above, the reporting requirements for each SPS misoperation should vary based on the attributes of the misoperation. The following discussion proposes reporting requirements and provides rationale for the type of SPS misoperation to which each should apply.

1. The SPS owner should be required to provide analysis of the misoperation to its Reliability Coordinator and Planning Coordinator for all SPS misoperations. The report should be provided to the Reliability Coordinator and the Planning Coordinator because such misoperations may require a reevaluation of the SPS under the review process proposed in the Study and Documentation Requirements section. The report should include the corrective action to assist the Reliability Coordinator and Planning Coordinator in confirming whether the SPS requires reevaluation.

2. The SPS owner should be required to develop and implement a corrective action plan for all SPS misoperations. Reporting details of the corrective action plan should be limited to purposes supporting reliability. As noted above, the report to the Reliability Coordinator and Planning Coordinator should include corrective actions. If an SPS must be removed from service or its operation is modified pending implementation of the corrective action plan, the status must be reported to the Reliability Coordinator, Transmission Operator, or Balancing Authority.

3. The SPS owner should be required to report for reliability metric purposes any SPS misoperation that involves a failure to operate or unnecessary operation. These attributes are analogous to protection system misoperations that must be reported and involve a failure of the SPS to operate per its installed design. The mechanism for

requiring reporting for reliability metric purposes should be similar to the process for reporting protection system misoperations under development in Project 2010-05.1: Protection Systems: Phase 1 (Misoperations).

4. The SPS owner should not be required to report or develop corrective action plans for other failures associated with an SPS that are not associated with an SPS operation or failure to operate, such as:
   - 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;
   - Unnecessary Arming – Any automatic arming of a SPS that occurs without the occurrence of the intended arming system condition(s); and
   - Failure to Reset – Any failure of a SPS to automatically reset following a return of normal system conditions, if the system design requires automatic reset.

These types of failures can be corrected by the SPS owner without involving the Reliability Coordinator and the Planning Coordinator, and are analogous to a protection system owner identifying a failed power supply on a relay. If the failure has not resulted in a misoperation then reporting and corrective action plans are not required. It should be noted however, that operational requirements apply and if an SPS must be removed from service the status must be reported to the Reliability Coordinator, Transmission Operator, or Balancing Authority.

Chapter 6 – Recommendations

Definition

The existing SPS definition in the NERC glossary lacks clarity and specificity necessary for consistent identification and classification of SPS. The following strawman definition is proposed.

Special Protection System

A scheme designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of faulted elements, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading.

Subject to the exclusions below, such schemes are designed to maintain system stability, acceptable system voltages, acceptable power flows, or to address other reliability concerns. They may execute actions that include but are not limited to: changes in MW and Mvar output, tripping of generators and other sources, load curtailment or tripping, or system reconfiguration.

The following schemes do not constitute an SPS in and of themselves:

a) Underfrequency or undervoltage load shedding

b) Locally sensing devices applied on an element to protect it against equipment damage for non-fault conditions by tripping or modifying the operation of that element, such as, but not limited to, generator loss-of-field or transformer top-oil temperature

c) Autoreclosing schemes

d) Locally sensed and locally operated series and shunt reactive devices, FACTS devices, phase-shifting transformers, variable frequency transformers, generation excitation systems, and tap-changing transformers

e) Schemes that prevent high line voltage by automatically switching the affected line

f) Schemes that automatically de-energize a line for non-fault operation when one end of the line is open

g) Out-of-step relaying

h) Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)

i) Protection schemes that operate local breakers other than those on the faulted circuit to facilitate fault clearing, such as, but not limited to, opening a circuit breaker to remove infeed so protection at a remote terminal can detect a fault or to reduce fault duty

j) Automatic sequences that proceed when manually initiated solely by an operator

k) Sub-synchronous resonance (SSR) protection schemes

l) Modulation of HVdc or SVC via supplementary controls such as angle damping or frequency damping applied to damp local or inter-area oscillations

m) A Protection System that includes multiple elements within its zone of protection, or that isolates more than the faulted element because an interrupting device is not provided between the faulted element and one or more other elements

Classification

SPS should be classified based on the type of event to which the SPS responds and the consequence of misoperation. Classification of SPS facilitates standard requirements commensurate with potential reliability risk. Four classifications are proposed:

- Type PS: planning – significant,
- Type PL: planning – limited,
- Type ES: extreme – significant, and
- Type EL: extreme – limited.

The planning classification applies to schemes designed to meet system performance requirements identified in the NERC Reliability Standards, while the extreme classification applies to schemes designed to limit the impact of two or more elements removed, an extreme event, or Cascading.

The significant classification applies to a scheme for which a failure to operate or inadvertent operation of the scheme can result in non-consequential load loss greater than or equal to 300 MW, aggregate resource loss (tripping or runback of generation or HVdc) greater than the largest Real Power resource within the interconnection, loss of synchronism between two portions of the system, or negatively damped oscillations. The limited classification applies to a scheme for which a failure to operate or inadvertent operation would not result in a significant impact.

Applicability to Functional Model Entities

Three of the existing SPS-related reliability standards (PRC-012-0, PRC-013-0, and PRC-014-0) assign requirements to the Regional Reliability Organization. These standards are not mandatory and enforceable because FERC identified them as fill-in-the-blank standards in Order No. 693. This report recommends that requirements be reassigned to users, owners, and operators of the bulk power system in accordance with the NERC Functional Model. The following recommendations are included in the report:

- Review of new or modified SPS – assign to Reliability Coordinators and Planning Coordinators.
- SPS database maintenance – assign to Planning Coordinators; have Planning Coordinators submit databases to NERC for maintenance of a continent-wide database.
- Assessment of existing SPS – assign Planning Coordinators and Transmission Planners responsibility to include SPS assessments in annual transmission planning assessments; assign Reliability Coordinators responsibility to coordinate a periodic assessment of SPS design and coordination.

Revisions to Reliability Standards

Figure 1 provides a high-level overview of recommendations related to the six PRC standards that apply to SPS. Recommendations include consolidating the six existing standards into three standards.

- Combine all requirements pertaining to review, assessment, and documentation of SPS (presently in PRC-012-0, PRC-013-0, PRC-014-0, and PRC-015-0) in one new standard, PRC-012-1. The requirement in PRC-012-0 for regional procedures for reviewing SPS misoperations is superseded by recommendations for revisions to PRC-016-0.1. The requirement in PRC-012-0 for regional maintenance and testing requirements is superseded by PRC-005-2.
- Requirements pertaining to analysis and reporting of SPS misoperations should be revised in a new standard, PRC-016-1. Due to the significant difference between protection systems and SPS, the subject of SPS misoperations should not be included in a future revision of PRC-004.
- Requirements pertaining to maintenance and testing of SPS already have been translated to PRC-005-2 by the Project 2007-17 Protection System Maintenance & Testing drafting team.

Additional detail is provided in Table 2 in Appendix C – Mapping of Requirements from Existing Standards. This table summarizes the recommendations for how each requirement in the existing six SPS-related standards should be mapped to revised standards. The more significant recommendations are summarized below.

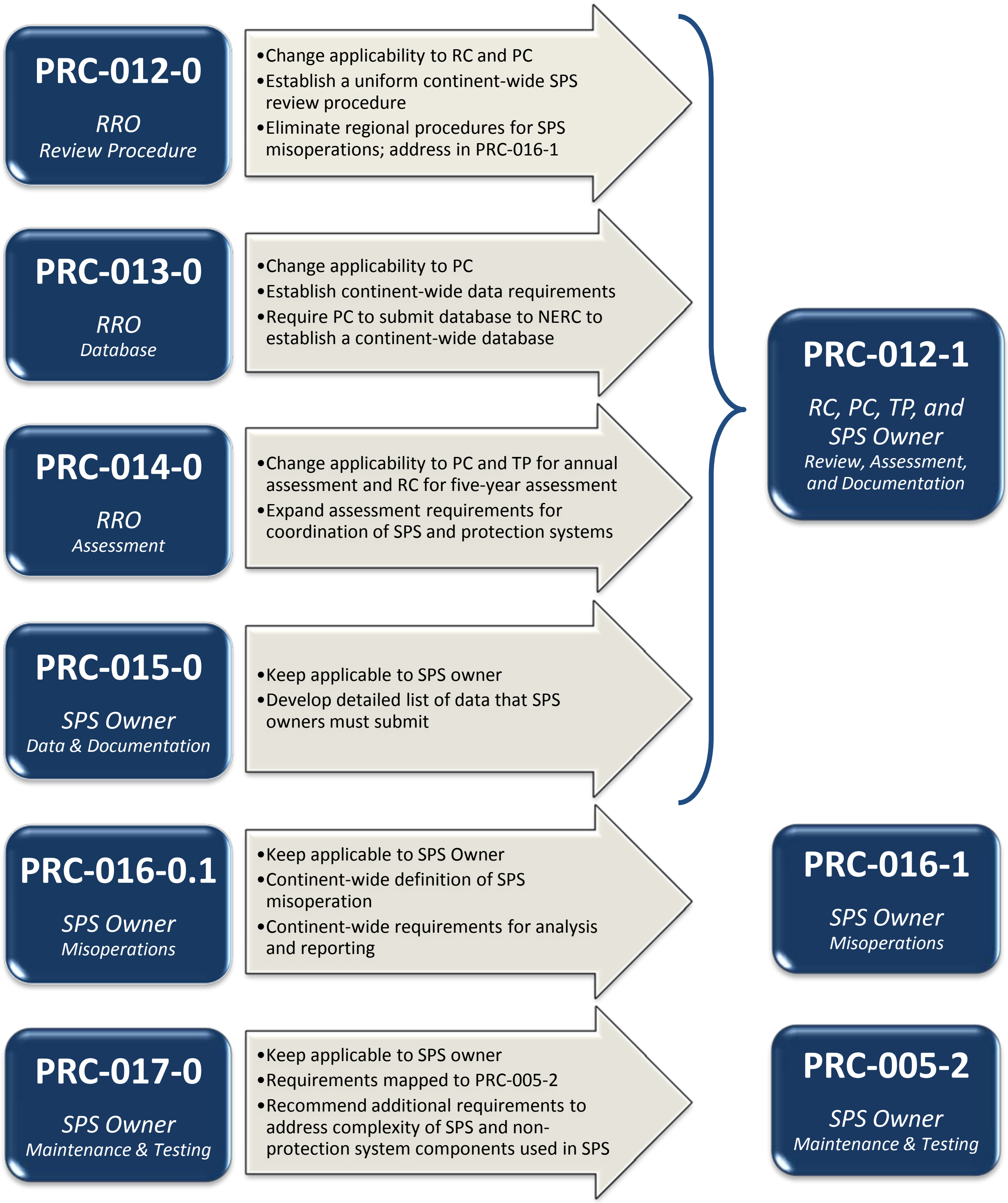


Figure 1 – Recommended Mapping of Existing PRC Standards

Standard PRC-012-1 – SPS Review, Assessment, and Documentation

- SPS owners should be required to design Type PL and Type PS SPS so that a single SPS component failure does not prevent the interconnected transmission system from meeting the performance requirements defined in NERC Reliability Standards TPL-001-0, TPL-002-0, or TPL-003-0.
- Existing requirements for regional procedures for reviewing new or modified SPS should be replaced with a continent-wide procedure assigned to Reliability Coordinators and Planning Coordinators to assure a wide-area view of both planning and operational aspects of SPS.
- Annual transmission planning assessments should include an assessment by the Planning Coordinator and Transmission Planner to review the operation, coordination, and effectiveness of SPS, including the effect of correct operation, a failure to operate, and inadvertent operations.
- Periodic comprehensive assessments (every five years or less) of SPS should be performed by the Reliability Coordinator, with support as requested from other entities, to assess whether SPS are still necessary, serves their intended purpose, meet relevant design criteria, coordinate with other SPS, UFLS, UVLS, and protection systems, and do not have unintended adverse consequences on reliability.
- Detailed continent-wide requirements for data submittals should be established for SPS owners proposing new or modified SPS. Detailed recommendations are included in this report.
- Planning Coordinators should be assigned responsibility for maintaining databases containing all information submitted by SPS owners. Planning Coordinators should be required to submit their databases to NERC so that NERC can maintain and make available a continent-wide SPS database.

Standard PRC-016-1 – SPS Misoperations

- PRC-016-1 should include a continent-wide definition of SPS misoperation based on the strawman definition proposed in this report.
- PRC-016-1 should include a continent-wide process for analysis of SPS operations and reporting SPS misoperations, including requirements for SPS owners to develop corrective action plans and provide analysis of SPS misoperations to Reliability Coordinators and Planning Coordinators.
- Reporting SPS operation and misoperation data for reliability metric purposes should be addressed outside PRC-016-1, in a manner similar to the process under development for reporting protection system misoperations in Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

Standard PRC-005-2 – Protection System Maintenance and Testing

- Maintenance and testing requirements for SPS should be expanded in the NERC Reliability Standards to address the complexity of testing SPS and the maintenance of non-protection system components used in SPS. These subjects should be addressed in a future revision of PRC-005 or development of a separate standard.

Recommendations to Be Included in Other Standards

This report discusses some aspects of SPS that are not addressed in the six SPS-related PRC standards. Recommendations should be incorporated in appropriate NERC Reliability Standards.

- SPS owners should be required to provide disturbance monitoring equipment to permit analysis of SPS performance following an event.
- Operating entities should be required to provide operators with documentation of procedures for operator interaction with SPS, and how operators should respond to SPS failures.
- All SPS should be monitored by SCADA/EMS with real-time status communicated that minimally includes whether the scheme is in-service, out-of-service, and the current operational state of the scheme.
- One entity should be assigned responsibility for monitoring, coordination, and control of an SPS.

Appendix A – Modeling and Simulation Considerations

The addition of two stable control systems does not necessarily result in a stable composite control system; the same is true for SPS. Although the SPS may not be directly linked in their actions, their composite actions and effect on the electric system for commonly-sensed system conditions or perturbations can often behave as a single control system. Therefore, it is imperative that they be evaluated for their potential to interact with each other, particularly during a system disturbance. The composite interaction of multiple SPS, or of SPS with UFLS, UVLS, or other protection systems could result in system instability or cascading.

Because of the complexity of some schemes, modeling them in system simulation is currently performed most often by monitoring their trigger conditions and manually mimicking their intended actions such as changing system configuration, switching reactive devices, and adjusting or tripping generation. Such manual manipulations in powerflow and dynamics studies are only effective when studying a single SPS unless an iterative process is used. Even then, manual manipulation may not be effective and may not be possible in studying the simultaneous actions of multiple SPS that could potentially interact with each other. The difficulty is most significant when considering the potential interaction of parameter-based SPS, since interaction with event-based SPS would occur only if the initial event and SPS operation caused a second event to occur.

It is sometimes possible to simulate the behavior of a single SPS through simulation tools such as user-defined scripts using vendor-provided or open-source programming capability, or standard relay models in the typical modeling and simulation software packages. However, doing so for the myriad of SPS that may exist, even in a portion of an interconnection, is cumbersome. Furthermore, simulating multiple SPS in real-time operations tools (e.g., EMS) for real-time contingency analysis is extremely difficult and often requires new and innovative algorithm and software development. In addition, models used in real-time systems are often abridged or reduced equivalents and may not permit accurate representation of a particular SPS's functions. All of these issues are extremely problematic given the sheer number of SPS in North American interconnections.

To assure SPS will function in a coordinated fashion may require that they be modeled and studied from their design inception in the planning horizon, through pre-seasonal system studies that determine transfer capabilities, and in the operating horizon from day-ahead planning through the real-time contingency analysis that system operators depend on for guidance. Present analysis methods are limited by the capability of the software tools and management of the SPS, and in some cases protection system, data. The industry should put emphasis on future developments in these areas.

General Considerations for Simulations

This section puts forth a number of factors, limitations, objectives, and overall guiding principles that a standard drafting team should consider in development of a new SPS standard with respect to the requirements for modeling and simulation, including data and process requirements necessary to support accurate and meaningful studies of SPS by Transmission Planners.

This report assumes that the modeling and simulation activities to be addressed are those performed for the planning horizon by Transmission Planning personnel. It is assumed that studies are performed using commercial off-the-shelf software packages and using databases derived from the interconnection-wide series of powerflow and dynamics cases. Studies using EMS based tools (e.g., study tools built into state estimators, real-time contingency analysis software, etc.) for real-time operations are not within the scope of this appendix.

It is important however, that the Transmission Planner share the results of planning horizon studies with operations personnel such that the impacts of SPS are effectively understood for the operating horizon also. This can be accomplished in a number of ways. Where operations support staff have similar study tools, sharing of the powerflow/dynamics cases, models, simulation scripts and similar data would enable them to evaluate SPS operation (or misoperation) for the operating horizon. Providing alarm or action limits for observable parameters (i.e., those that could be monitored in the operating environment) related to SPS operation would be another possibility. In this case, the parameters may be a direct indication or a proxy value that is indicative of the system condition of concern. Regardless of the process employed, the overriding consideration is that study results are adequately translated into actionable intelligence that is available to and understood by the system operator. While this is not intended to create a recommendation for a specific SPS standard requirement, how this would ultimately be accomplished should be kept in mind as SPS standards are developed and implemented.

As a general rule, SPS are conceived by transmission planning engineers and implemented by protection and control engineers. To some extent, the engineers in these two groups are concerned with different aspects of SPS operation and use different terminology to describe SPS (and other system) functions. For example, a transmission planner may consider a protection system component failure to be a contingency while a protection engineer may consider this to be a design consideration. Transmission planning engineers conceive an SPS as a solution to system-level problems. Their focus is on the “big picture” functional operation of the SPS for specific system level conditions. Protection and control engineers implement an SPS via detailed design using various sensors, relays, etc. Their focus is on efficiently implementing the functional requirements as they understand them to be. It is imperative that the planning engineers effectively communicate the requirements of the SPS to protection engineers and monitor the design and implementation of the scheme to ensure that the SPS is implemented and functions as prescribed by the planner.

The planning and protection engineers should also consult with the operations personnel to ensure that possible system-level events which might result in unintended SPS operation are considered. Involving operations personnel at each stage of the design process will help ensure that the range of operating conditions likely to be encountered in the real world (including outages), as well as practical operating considerations, are also adequately considered in the SPS design and implementation.

An explicit requirement should exist to represent the salient features of SPS operation in a form that can be readily shared with, understood by, and used in simulations by other Transmission Planners. Simulation of SPS in powerflow or dynamic studies may involve a combination of using standard relay models, various monitoring features, and scripts or program code to adequately simulate the functioning of the SPS. These may include user-defined scripts using vendor-provided or open-source programming capability, or standard relay models in the typical modeling and simulation software packages (either executed during solution-run time or as user-written dynamic models), etc. Transmission Planners generally have their own individual preferences as to how to reflect these functions when performing simulations. Additionally, different Transmission Planning organizations have different levels of expertise in developing scenarios to reflect actual system operation and performing simulations based on those scenarios. Therefore, it is important that the modeling information to be used by other Transmission Planning engineers as input (including run scripts) in simulations be simple, understandable and well documented. Any scripts or models provided need to be “open source” in nature and well-documented to enable independent verification. The use of user models, FORTRAN object code, compiled scripts, and similar which make it difficult for the receiving Transmission Planner to review and understand how the SPS model functions must be avoided.

In addition to providing the relay models, program code/script, and similar input as part of the database, a summary document should be provided explaining the SPS. The information shared must include a summary and guidance document which includes the following, as applicable.

- An overview explanation of the basic functioning of the SPS, describing when and how it operates
- A listing of the setpoints applicable to the SPS (e.g., relay trip settings, etc.)
- A summary overview of how the SPS is being simulated via relay models, simulation scripts that may be provided
- Specific bus numbers, branch identifiers, machine identifiers, etc. should be referenced to help the Transmission Planner receiving this information understand how the SPS is being simulated

SPS modeling information should be readily available as part of the interconnection-wide modeling processes, but not an integral part of an interconnection-wide case year database. Specific recommendations are included in the chapter on study and documentation requirements.

Because of the special nature of SPS, it is not practical or even possible to include them in the interconnection-wide load flow and/or dynamic database case years in the classic sense (e.g., such as one would include a generator or FACTS device model). Additionally, it is simply not necessary to model all SPS for all simulations. The reality is that an SPS in the Northeast will likely have very little impact on the results of simulations focused on the Southeast. Therefore, including all SPS in all simulations places an unreasonable burden on Transmission Planners. However, due consideration should be given to the interaction of a given SPS with other SPS. Note that geographical distance alone may not be sufficient justification not to consider the interaction of several SPS.

However, it is important that information about all SPS be available for use, as deemed appropriate by the Transmission Planners whose systems may be affected by the SPS operation (or misoperation). It is also important the relevant parameter-based SPS be modeled concurrently in simulations to appropriately evaluate potential interactions among the SPS.

Therefore, the data management process for providing SPS information for simulations purposes should include the following considerations.

- Sufficiently detailed SPS information and documentation as described above can be managed as part of the interconnection-wide powerflow and dynamic case creation process.
- Providing the models and simulation scripts alone is not sufficient. A functional description to assist the Transmission Planner in understanding how these modeling/simulation elements work to emulate the SPS function is necessary in order for the Transmission Planner to properly simulate and interpret the results of simulations involving the SPS.
- The SPS information may reside separately from the interconnection-wide powerflow and dynamic cases, but a clear association to each case must be evident.
- Each Transmission Planner will be able to select the SPS that are relevant to the simulation they are performing. Engineering judgment, with a documented reason, for excluding SPS from simulations is acceptable.
- Where included, the impact of multiple SPS and their interaction should be reasonably accounted for in the simulation activities.

It is envisioned that Transmission Planners will generally include only those SPS that, in their judgment, are relative to the simulations being performed and/or could potentially interact with other SPS being included in these simulations. However, it would be prudent to have some big picture check for unintended SPS interaction. Therefore, a joint, interconnection-wide study or assessment should be periodically performed to evaluate potential interactions among SPS across the entire interconnection. Such a study or assessment should include modeling and simulation of all of the SPS throughout the interconnection. A periodicity of five years for this joint study is suggested as an appropriate time frame.

Use of SPS Simulations in Transmission Planning Studies

SPS are used as alternatives to transmission infrastructure to support reliable system operation for identified concerns. As such, these schemes must be analyzed in transmission planning analyses just as any other transmission system addition would be, with a focus on:

- Operation as expected for the design case of concern
- Understanding the potential for operation beyond the original design intent
- Determining if there is a potential for failure to operate to rectify the design case of concern.

In system planning, the types of studies which are typically performed to determine system performance are powerflow and dynamic simulations and analyses. SPS need to be modeled in both of these types of studies.

Powerflow (i.e., steady-state) SPS modeling techniques which could be employed include:

- Explicit modeling of the SPS monitoring and consequent actions with scripting and programming automatically called during powerflow processing
- Explicit modeling of the actuation of the SPS in contingencies which are expected to cause the SPS to actuate
- Contingencies are included in the analysis with and without the SPS actuated
- Monitoring of system performance to determine if system conditions would actuate an SPS

  - The monitoring occurs for all contingencies examined
  - Any result indicating potential actuation of an SPS is rerun with the SPS actuated

Dynamic (i.e., stability) SPS modeling techniques which could be employed include:

- Explicit modeling of the SPS in the dynamic simulation with a model that includes the monitoring and consequent actions during the dynamic simulations
- Explicit modeling of the actuation of the SPS in contingencies which are expected to cause the SPS to actuate
- The dynamic/stability contingencies are included in the analysis with and without the SPS actuated
- Monitoring of SPS trigger elements (voltage, current, flow and/or frequency on system elements or element status) to determine if actuation of an SPS would have actuated
  - Rerun the simulation with the SPS actuated if the monitored results indicate potential actuation of the SPS

The SPS modeling techniques used in system planning should be based upon modeling information provided by the SPS owner which clearly describes what the SPS senses and the consequent actions taken when its triggering needs are met.

The need for accurate modeling information can be demonstrated with an example. In the example, two SPS exist in an area. One SPS trips a large generating plant for loss of a transmission circuit due to first swing stability concerns. This SPS acts within cycles of the initiating line loss. The second SPS inserts a series reactor into a transmission circuit to limit flow and eliminate an overload on the circuit. The second SPS acts within seconds (5 seconds for this example) of the overload condition occurring.

Steady state studies of the area where these SPS exist would examine the representative cases (sets of system conditions) and contingency sets for the study in question. If the power flow software allowed, a post-solution program could be run to test if the actuating circumstances for each SPS were met; if so, the contingent solution would be rerun and tested again for any other SPS which would actuate. If the power flow software did not have this flexibility, the engineer could include an SPS actuation for those contingencies expected to trigger the SPS and run that expanded contingency list; the results could be examined with attention paid to the loading for the circuit protected by the second SPS. Any contingencies which caused an overload on the triggering circuit could be rerun with the SPS actuated.

Since both SPS act within the dynamic simulation timeframe, the SPS should be modeled or monitored in stability simulations. Dynamic models could exist for both SPS. Should the flow on the SPS-triggering line exceed the flow actuation setpoint for the required time duration, the dynamic simulation would capture the impact of the reactor insertion and the SPS actuation. If the SPS were not explicitly modeled, their trigger values could be monitored (i.e., the status or flow on the line for the first SPS and the flow on the potentially overloaded circuit for the second SPS). The monitored data channels would be examined after each simulation to determine if the simulation needed to be rerun while modeling the appropriate SPS actions.

The goal for modeling SPS in studies is to confirm that they will operate to correct the intended system concerns as necessary to preserve acceptable system performance. In addition, the analyses provide understanding for system planning and operations on when and how the use of the SPS may change over time. This information may be critical for system operations staff to maintain reliable system operation.

Appendix B – Operational Considerations

This information is a high level list of important issues and concerns if performing SPS analyses in real-time operations.

Real-time SPS Evaluation

Current system conditions must be identified before evaluating whether an SPS would perform its function and achieve its desired outcome. Results of security analysis should be required to indicate whether an SPS should be armed (if armed manually) and whether an SPS will operate for a given contingency. Security analysis should model operation of the SPS in addition to the initiating contingency when the SPS is armed.

SPS evaluation often cannot be done with SCADA input alone. Some non-SCADA input may be needed; for example, limits from off-line studies are converted into inputs available in the Energy Management System (EMS). The inputs that support SPS evaluation and operation need to be codified in operating guides and presented on operator displays for ease of use and operation. Custom code and displays are generally required to aggregate all needed information for usage by engineers and operators in real time.

The impact of SPS operation on facilities external to the SPS owner/operator needs to be jointly considered and communicated to external entities and appropriately accounted for in EMS. Furthermore, the effects of external contingencies on the SPS triggers should be accounted for within EMS and known to operators.

SPS evaluation typically involves the testing of a limited set of relevant contingencies, requiring the use Real-Time Contingency Analysis (RTCA). In some cases, a dc solution to identify thermal issues is adequate; in other cases, a full ac solution is required (e.g., where triggers are voltage dependent).

Some EMS are not robust enough to compute ac solutions in EMS/RTCA. Depending on the classification of an SPS (e.g., significant), an EMS/RTCA with such limited capability would be insufficient to evaluate the impact of the SPS. In such cases it is necessary to establish other means, such as supplemental off-line tools or delegation of this analysis to an entity that has this capability, to study the operational impacts of the SPS.

If the EMS/RTCA does not reach a solved state, then the SPS cannot be evaluated. For example, some EMS/RTCA will fail to solve or fail to converge upon the creation of islands in the model. In these cases, SPS modeling may require custom software solutions.

Multiple Decision-Making Capability

When evaluating SPS in EMS/RTCA, intermediate steps must be modeled and intermediate states must be evaluated. It should be assumed that an SPS may suffer a full or partial failure and that system conditions will change as the SPS operates. Adverse conditions may arise during intermediate steps that lead to undesired outcomes or put the system into an unplanned operating state.

The post-contingency, pre-SPS-operation state must be known to assess system conditions before the SPS action can be evaluated. For example, the loss of a large nuclear station automatically activates a large emergency core cooling load. This new system state would require a re-solution to check post-contingent node voltage (i.e., with the load connected) before consideration of SPS activation and results can occur. This requires that several stages and intermediate actions be modeled in the evolution of the final system topology to ensure that the system can reach the desired end-state.

Information Management

Each SPS may have its own set of arming and activation triggers. Examples include equipment status, line loading and voltage. These triggers may be complex, and could affect the alarming capability required of EMS.

Changes to EMS models may require long lead times before an SPS can be implemented; for example, changes to models often require pushing through multiple staged software environments. Entities should use software designs that are flexible to accommodate timely changes to SPS models that might not be tied to the network model database release schedule. When implementing an SPS before the EMS model can be updated, it is necessary to establish other means, such as supplemental off-line tools or delegation of this analysis to an entity that has this capability, to study the operational impacts of the SPS.

Modeling Simplicity and Usability

Complex SPS schemes require due diligence to maintain and support. Entities should be required to develop and document an efficient approach to SPS control. An entity's strategy should allow for concurrent and/or consecutive SPS actions.

Appendix C – Mapping of Requirements from Existing Standards

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-012-0	R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include:	PRC-012-1 should define a continent-wide SPS review procedure conducted by the Reliability Coordinator and Planning Coordinator.	See Review and Approval of New or Modified SPS on pp. 16-17.
PRC-012-0	R1.1. Description of the process for submitting a proposed SPS for Regional Reliability Organization review.	PRC-012-1 should define a continent-wide SPS review procedure conducted by the Reliability Coordinator and Planning Coordinator.	See Review and Approval of New or Modified SPS on pp. 16-17.
PRC-012-0	R1.2. Requirements to provide data that describes design, operation, and modeling of an SPS.	PRC-012-1 should define continent-wide requirements for SPS owners to provide data that is clear and understandable to all entities that require this information to plan and operate the bulk power system.	See Data Submittals by Entities that Own SPS on pp. 18-19.
PRC-012-0	R1.3. Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS 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.	PRC-012-1 should require that all Type PS and PL SPS are designed so system performance requirements are met in the event of a single component failure within the SPS.	See SPS Single Component Failure Requirements on p. 14-15

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-012-0	R1.4. Requirements to demonstrate that the inadvertent operation of an SPS 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.	PRC-012-1 should require that an entity proposing a new or modified SPS should be required to submit studies that demonstrate the operation, coordination, and effectiveness of the SPS, including the impacts of a correct operation, a failure to operate, and inadvertent operation.	See Review and Approval of New or Modified SPS on p. 16.
PRC-012-0	R1.5. Requirements to demonstrate the proposed SPS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.	PRC-012-1 should require that an entity proposing a new or modified SPS should be required to submit studies that demonstrate the operation, coordination, and effectiveness of the SPS, including the impacts of a correct operation, a failure to operate, and inadvertent operation.	See Review and Approval of New or Modified SPS on p. 16.
PRC-012-0	R1.6. Regional Reliability Organization definition of misoperation.	A continent-wide definition of an SPS misoperation should be established.	See SPS Misoperation Definition on p. 22.
PRC-012-0	R1.7. Requirements for analysis and documentation of corrective action plans for all SPS misoperations.	Do not carry forward to revised standards.	The need for this requirement is eliminated by establishing continent-wide requirements in PRC-016-1. See SPS Operation Review Process on pp. 23-24.
PRC-012-0	R1.8. Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure.	Do not carry forward to revised standards.	The need for this requirement is eliminated by establishing a continent-wide review procedure within PRC-012-1. See Review and Approval of New or Modified SPS on pp. 16-17.
PRC-012-0	R1.9. Determination, as appropriate, of maintenance and testing requirements.	Do not carry forward to revised standards.	The need for this requirement is eliminated by establishing continent-wide maintenance and testing requirements within PRC-005-2.

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-012-0	R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its SPS review procedure on request (within 30 calendar days).	Do not carry forward to revised standards.	Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information.
PRC-013-0	R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with an SPS installed shall maintain an SPS database. The database shall include the following types of information:	PRC-012-1 should require that each Planning Coordinator maintain a database, and provide the database to NERC for the purpose of maintaining a continent-wide database.	See SPS Database on p. 19.
PRC-013-0	R1.1. Design Objectives — Contingencies and system conditions for which the SPS was designed,	This information is included in a comprehensive list of data requirements to be provided by the SPS owner and maintained in a database by the Planning Coordinator.	See Data Submittals by Entities that Own SPS on pp. 18-19 and SPS Database on p. 19.
PRC-013-0	R1.2. Operation — The actions taken by the SPS in response to Disturbance conditions, and	This information is included in a comprehensive list of data requirements to be provided by the SPS owner and maintained in a database by the Planning Coordinator.	See Data Submittals by Entities that Own SPS on pp. 18-19 and SPS Database on p. 19.
PRC-013-0	R1.3. Modeling — Information on detection logic or relay settings that control operation of the SPS.	This information is included in a comprehensive list of data requirements to be provided by the SPS owner and maintained in a database by the Planning Coordinator.	See Data Submittals by Entities that Own SPS on pp. 18-19 and SPS Database on p. 19.

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-013-0	R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).	Do not carry forward to revised standards.	Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information.
PRC-014-0	R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all SPSs installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.	PRC-012-1 should require the Planning Coordinator and Transmission Planner to assess SPS in annual transmission planning assessments and require the Reliability Coordinator to conduct a periodic review every five years, or sooner if significant changes are made to the system topology or operating characteristics that may impact the coordination among SPS and between SPS and UFLS, UVLS, and other protection systems.	See Periodic Comprehensive Assessments of SPS Coordination on p. 17.
PRC-014-0	R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all SPSs installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).	Do not carry forward to revised standards.	Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information.
PRC-014-0	R3. The documentation of the Regional Reliability Organization's SPS assessment shall include the following elements:	PRC-012-1 should require the Reliability Coordinator to document its periodic assessments. The documentation should include the same elements required in a study supporting approval of a new or modified SPS.	See Review and Approval of New or Modified SPS on pp. 16-17 and Assessment of Existing SPS on p. 17.
PRC-014-0	R3.1. Identification of group conducting the assessment and the date the assessment was performed.	This list of elements includes: • Entity conducting the study • Study completion date	See Review and Approval of New or Modified SPS on pp. 16-17.

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-014-0	R3.2. Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.	This list of elements includes: • Study years • System conditions • Contingencies analyzed • Study completion date	See Review and Approval of New or Modified SPS on pp. 16-17.
PRC-014-0	R3.3. Identification of SPSs that were found not to comply with NERC standards and Regional Reliability Organization criteria.	PRC-012-1 should require the Planning Coordinator and Transmission Planner document and submit any issues identified in the annual assessment to the Reliability Coordinator. PRC-012-1 should require the Reliability Coordinator to document and submit any issues identified in the periodic assessment to the SPS owner.	See Assessment of Existing SPS on p. 17.
PRC-014-0	R3.4. Discussion of any coordination problems found between a SPS and other protection and control systems.	PRC-012-1 should require the Reliability Coordinator to request the Planning Coordinator and Transmission Planner to assess and document whether the SPS is still necessary, serves its intended purpose, meets performance criteria, coordinates with other SPS, UFLS, UVLS, and protection systems, and does not have unintended adverse consequences on reliability.	See Periodic Comprehensive Assessments of SPS Coordination on p. 17.
PRC-014-0	R3.5. Provide corrective action plans for non-compliant SPSs.	PRC-012-1 should require that if issues are identified in an annual or periodic assessment, the Reliability Coordinator and Planning Coordinator determine, in consultation with the SPS owner, whether a corrective action plan is required, and if so, whether the SPS can remain in service until a corrective action plan is implemented. If a corrective action plan is required, PRC-012-1 should require the SPS owner to submit an application for a new or modified SPS.	See Assessment of Existing SPS on p. 17.

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-015-0	R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed SPSs as specified in Reliability Standard PRC-013-0_R1.	PRC-012-1 should define continent-wide requirements for SPS owners to provide data that is clear and understandable to all entities that require this information to plan and operate the bulk power system.	See Data Submittals by Entities that Own SPS on pp. 18-19.
PRC-015-0	R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.	Do not carry forward to revised standards. PRC-012-1 should have a requirement for the SPS owner to file an application for approval of an SPS, which assures that the SPS is reviewed in accordance with the continent-wide review procedure prior to being placed in service.	See Review and Approval of New or Modified SPS on pp. 16-17.
PRC-015-0	R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of Studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).	Do not carry forward to revised standards.	Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information.
PRC-016-0.1	R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all misoperations in accordance with the Regional SPS review procedure specified in Reliability Standard PRC-012-0_R1.	PRC-016-1 should establish a continent-wide process for analyzing and reporting SPS misoperations.	See SPS Operation Review Process on pp. 23-24.

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-016-0.1	R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations.	PRC-016-1 should establish a requirement that the SPS owner should be required to develop and implement a corrective action plan for SPS misoperations.	See SPS Operation Review Process on pp. 23-24.
PRC-016-0.1	R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).	Do not carry forward to revised standards.	Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information.
PRC-017-0[21]	R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place. The program(s) shall include:	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, R1.
PRC-017-0	R1.1. SPS identification shall include but is not limited to:	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, Tables 1-1 – 1-5, and Table 2.
PRC-017-0	R1.1.1. Relays.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, Table 1-1.
PRC-017-0	R1.1.2. Instrument transformers.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, Table 1-3.
PRC-017-0	R1.1.3. Communications systems, where appropriate.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, Table 1-2.

[21] Mapping for requirements in PRC-017-0 are adapted from the mapping document developed by the Project 2007-17 Protection System Maintenance & Testing drafting team.

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-017-0	R1.1.4. Batteries.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, Table 1-4.
PRC-017-0	R1.2. Documentation of maintenance and testing intervals and their basis.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, R1 and R2.
PRC-017-0	R1.3. Summary of testing procedure.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, R1, Tables 1-1 – 1-5, and Table 2.
PRC-017-0	R1.4. Schedule for system testing.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, R1 and R2.
PRC-017-0	R1.5. Schedule for system maintenance.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, R1 and R2
PRC-017-0	R1.6. Date last tested/maintained.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, R3 and associated Measures, R4 and associated Measure, and Data Retention.
PRC-017-0	R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).	Addressed by Project 2007-17, Protection System Maintenance and Testing; this requirement is not carried forward to the revised standard.	Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information.

Appendix D – Standards Committee Request for Research; January 9, 2011

Request for Research

Project 2010-05.2
Phase 2 of Protection Systems: SPS and RAS

Introduction

NERC's Standards Committee has tentatively identified this project for initiation in late 2012. Prior to then, there is a need for additional research and scoping of the project to determine:

- What is the problem that this project will try to solve?
- Is the development of a standard the appropriate manner to solve that problem, or should alternative approaches be used?
- If a standard is appropriate, what is the recommended solution to the problem?

Results based standards projects use the approach of defining the needs, goals, and objectives for the project. For this project, we would like your assistance in this effort. Below is a draft problem statement for your consideration.

Need (Problem)

Special Protection Systems (SPS) and Remedial Action Schemes (RAS) can misoperate and negatively impact the reliability of the BES.

Does the need above correctly document the concern described in the attached draft SAR?

Do you agree that this is a problem that needs to be addressed?

Is a standard the appropriate vehicle to address this problem, or should an alternative approach be used? If an alternative, is recommended, what would that alternative be?

If development of a standard is appropriate, then please consider the following Goal

Goal (Solution)

Require the analysis, reporting, and correction of Misoperations of SPS and RAS.

Request

Please provide the Standards Committee with the following information:

- An updated Need/Problem (or a statement of concurrence with the draft presented here)
- A statement indicating whether or not you believe this problem is one which needs to be addressed
- If you agree the problem needs to be addressed, a suggestion for how to address the problem
- If you suggest a standard be developed to address the problem, then please provide
    - An updated goal (or a statement of concurrence with the draft presented here)
    - A set of objectives in support of that goal
    - If you have any suggested changes to the attached draft SAR, please propose them
    - If you have specific recommendations for requirements language or additional information, please include them

Thank you in advance for your assistance.

Appendix E – Scope of Work Approved by the Planning Committee; June 8, 2011

Assessment of Special Protection System Standards and Regional Practices

Proposal:

The SPCS proposes to conduct an assessment of the SPS-related PRC standards and definition of SPS, conduct an assessment of existing regional practices summarizing commonality and differences, and to document its findings in a report to the Planning Committee that can serve as a reference document for a standard drafting team that ultimately will be assigned to review these standards. If deemed appropriate, the report could be used to support a Compliance Application Notice (CAN) to address part of this issue until a revised definition and standard(s) are developed. The SPCS further proposes this activity should be a joint effort with the Transmission Issues Subcommittee (TIS).

Rationale:

- The SPCS scope calls for providing subject matter expertise for NERC Standards related to protection systems and controls, and the SPCS work plan includes an assignment to review all existing PRC-series Reliability Standards, to advise the Planning Committee of its assessment, and to develop Standards Authorization Requests, as appropriate, to address any perceived deficiencies.
- The SPCS has reviewed all PRC standards except the group of SPS standards. The SPCS had started assessment of these standards, but the assessment was deferred due to other priority work such as the Power Plant and Transmission System Protection Coordination technical reference document.
- The SPCS has reviewed its work plan and determined that this is the next logical project for the SPCS. Work on the Transmission System Phase Backup Protection reliability guideline is wrapping up at this time and the SPCS can make the SPS review one of two priority activities for this year (the other is the document addressing operation of protection systems in response to power swings).
- The SPCS believes that a thorough review of SPS-related PRC standards would benefit from the expertise of TIS and the SPCS recommends a joint SPCS/TIS effort coordinated by the SPCS. This proposal has been reviewed with and is supported by TIS.
- The SPCS proposes to conduct an assessment of the standards and definition of SPS, and conduct an assessment of existing regional practices summarizing commonality and differences among the various regional practices.
- The SPCS believes that differences among regional practices must be resolved through a formal process; a consensus opinion of what constitutes an SPCS would lack standing unless it is vetted through a stakeholder process. The SPCS proposes to document its findings in a report that can serve as a reference document for a standard drafting team that ultimately will be assigned to review these standards. If deemed appropriate, the report could be used to support a CAN to address part of this issue until a revised standard(s) is developed.
- The scope of work for such a review is significant and direction should come through the NERC Planning Committee as the body to which SPCS and TIS report.
- The SPCS believes that an appropriate time frame for completing this report would be to submit a draft to the Planning Committee at its March 2012 meeting. The SPCS and TIS believe this schedule is appropriate to support a thorough review.

Approved by the NERC Planning Committee
June 8, 2011

Appendix F – System Analysis and Modeling Subcommittee Roster

John Simonelli
Chair
Director - Operations Support Services
ISO New England

K. R Chakravarthi
Vice Chair
Manager, Interconnection and Special Studies
Southern Company Services, Inc.

G Brantley Tillis, P.E.
RE – FRCC
Manager, Transmission Planning Florida
Progress Energy Florida

Kiko Barredo
RE – FRCC – Alternate
Manager, Bulk Transmission Planning
Florida Power & Light Co.

Thomas C. Mielnik
RE – MRO
Manager Electric System Planning
MidAmerican Energy Co.

Salva R. Andiappan
RE – MRO – Alternate
Manager - Modeling and Reliability Assessments
Midwest Reliability Organization

Donal Kidney
RE – NPCC
Manager, System Compliance Program Implementation
Northeast Power Coordinating Council

Bill Harm
RE – RFC
Senior Consultant
PJM Interconnection, L.L.C.

Mark Byrd
RE – SERC
Manager - Transmission Planning
Progress Energy Carolinas

Gary T Brownfield
RE – SERC – Alternate
Supervising Engineer, Transmission Planning
Ameren Services

Jonathan E Hayes
RE – SPP
Reliability Standards Development Engineer
Southwest Power Pool, Inc.

Kenneth A. Donohoo
RE – TRE
Director System Planning
Oncor Electric Delivery

Hari Singh
RE – WECC
Transmission Asset Management
Xcel Energy, Inc.

Kent Bolton
RE – WECC – Alternate
Staff Engineer
Western Electricity Coordinating Council

Digaunto Chatterjee
ISO/RTO
Manager of Transmission Expansion Planning
Midwest ISO, Inc.

Patricia E Metro
Cooperative
Manager, Transmission and Reliability Standards
National Rural Electric Cooperative Association

Eric Mortenson, P.E.
Investor-Owned Utility
Principal Rates & Regulatory Specialist
Exelon Business Services Company

Amos Ang, P.E.
Investor-Owned Utility
Engineer, Transmission Interconnection Planning
Southern California Edison

Bob Cummings
NERC Staff Coordinator
Senior Performance and Analysis Engineer
NERC

Appendix G – System Protection and Control Subcommittee Roster

William J. Miller
Chair
Principal Engineer
Exelon Corporation

Philip B. Winston
Vice Chair
Chief Engineer, Protection and Control
Southern Company

Michael Putt
RE – FRCC
Manager, Protection and Control Engineering Applications
Florida Power & Light Co.

Mark Gutzmann
RE – MRO
Manager, System Protection Engineering
Xcel Energy, Inc.

Richard Quest
RE – MRO – Alternate
Principal Systems Protection Engineer
Midwest Reliability Organization

George Wegh
RE – NPCC
Manager
Northeast Utilities

Quoc Le
RE – NPCC -- Alternate
Manager, System Planning and Protection
NPCC

Jeff Iler
RE – RFC
Principal Engineer, Protection and Control Engineering
American Electric Power

Therron Wingard
RE – SERC
Principal Engineer
Southern Company

David Greene
RE – SERC -- Alternate
Reliability Engineer
SERC Reliability Corporation

Lynn Schroeder
RE – SPP
Manager, Substation Protection and Control
Westar Energy

Samuel Francis
RE – TRE
System Protection Specialist
Oncor Electric Delivery

David Penney, P.E.
RE – TRE – Alternate
Senior Reliability Engineer
Texas Reliability Entity

Baj Agrawal
RE – WECC
Principal Engineer
Arizona Public Service Company

Miroslav Kostic
Canada Provincial
P&C Planning Manager, Transmission
Hydro One Networks, Inc.

Sungsoo Kim
Canada Provincial
Section Manager – Protections and Technical Compliance
Ontario Power Generation Inc.

Michael J. McDonald
Investor-Owned Utility
Principal Engineer, System Protection
Ameren Services Company

Jonathan Sykes
Investor-Owned Utility
Manager of System Protection
Pacific Gas and Electric Company

Charles W. Rogers
Transmission Dependent Utility
Principal Engineer
Consumers Energy Co.

Joe T. Uchiyama
U.S. Federal
Senior Electrical Engineer
U.S. Bureau of Reclamation

Daniel McNeely
U.S. Federal – Alternate
Engineer - System Protection and Analysis
Tennessee Valley Authority

Philip J. Tatro
NERC Staff Coordinator
Senior Performance and Analysis Engineer
NERC

Appendix H – Additional Contributors

Forrest Brock
Transmission Compliance Specialist
Western Farmers Electric Cooperative

Robert Creighton
Sr. Engineering Specialist, Transmission Planning
Nova Scotia Power, Inc.

Tom Gentile
Senior Director, Transmission Northeast
Quanta Technology

Bryan Gwyn
Senior Director, Protection and Control Asset Management
Quanta Technology

Gene Henneberg
Staff Protection Engineer
NV Energy

Greg Henry (formerly NERC Staff Coordinator for SAMS)
Lead Engineer, Smart Integrated Infrastructure
Black & Veatch

Bobby Jones
Planning Manager – Stability
Southern Company Services

John O'Connor
Principal Engineer
Progress Energy Carolinas

Slobodan Pajic
Senior Engineer, Energy Consulting
GE Energy Management

Appendix I – Revision History

Revision History		
Version	**Date**	**Modification(s)**
0	March 5, 2013	Initial Document
0.1	April 18, 2013	Appendix A – Correction to remove trade names and replace with generic language in the section, General Considerations for Simulation

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2008-02 Undervoltage Load Shedding

Recommended Coordination Plan | March 14, 2014

Background

Project 2008-02 Undervoltage Load Shedding ("UVLS Project") proposes to consolidate and retire PRC-010-0, PRC-020-1, PRC-021-1, and PRC-022-1 to create PRC-010-1 – Undervoltage Load Shedding. During development, the drafting team identified the following necessary corresponding changes to meet the design of PRC-010-1:

1) Modify PRC-004-3 – Protection System Misoperation Identification and Correction, which excludes UVLS, to include certain types of UVLS programs as part of its applicable facilities.

2) Retire three requirements in EOP-003-2 – Load Shedding Plans whose required performance is reflected in proposed PRC-010-1.

3) Modify the current NERC Glossary definition of the term Special Protection System (SPS), which excludes UVLS, to include a subset of UVLS programs that are more appropriately categorized as SPSs and covered by SPS-related standards.

In order to make the necessary changes, the UVLS Project needs to coordinate with ongoing development work in three active NERC standard development projects as follows:

- Project 2010-05.1 Protection Systems: Phase 1 (Misoperations) ("Misoperations Project")
- Project 2009-03 Emergency Operations ("EOP Project")
- Project 2010-05.2 Protection Systems: Phase 2 (Special Protection Systems) ("SPS Project")

Current Recommended Plan

As a result, NERC has identified a preferred project plan to coordinate the above-mentioned projects to properly align legacy standard retirements and revised standard implementations due to the differences in each project’s timing. In short, the revised SPS definition, the UVLS Project, and the EOP Project will be presented simultaneously to industry, the NERC Board of Trustees, and applicable regulatory authorities. An illustrative diagram of this coordination appears on the next page. This plan is subject to change as necessary.

1) The UVLS Project will address the conforming changes needed to PRC-004 after PRC-004-3 is complete. How and when this will occur depends on when PRC-004-3 obtains approval from the ballot body and is adopted by the NERC Board of Trustees.

2) The EOP and UVLS Projects will progress simultaneously and coordinate necessary changes.

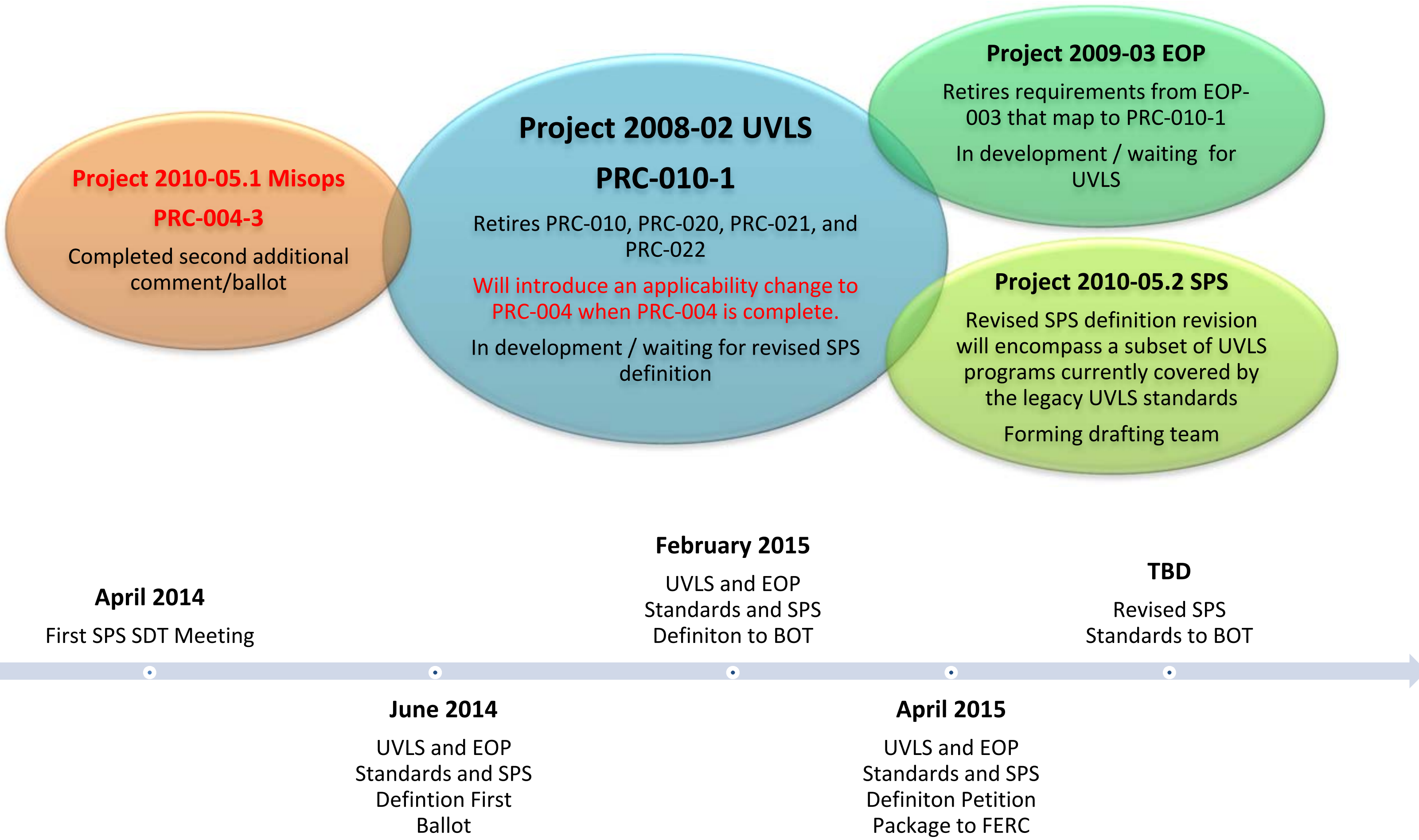
3) The SPS Project is proposing to revise the definition of SPS in advance of revising the SPS standards. The UVLS Project will progress simultaneously with the SPS definition revision in order to properly transfer certain aspects of the legacy UVLS standards into coverage under the SPS standards.

Impacts

As a result of the necessary coordination above, the UVLS Project and the EOP Project are now timed by the schedule for the SPS Project, which is targeting the approval of the revised SPS definition at the February 2015 NERC Board of Trustees meeting.

Additional Considerations

Of note, Project 2007-17.3 Protection System Maintenance and Testing: Phase 3 (Sudden Pressure Relays) is beginning development on version 4 of PRC-005, which may consider use of a new defined term introduced by the UVLS Project. Therefore, this project may also coordinate with the UVLS Project as needed.


Project 2010-05.1 Misops
PRC-004-3
Completed second additional comment/ballot
Project 2008-02 UVLS
PRC-010-1
Retires PRC-010, PRC-020, PRC-021, and PRC-022
Will introduce an applicability change to PRC-004 when PRC-004 is complete.
In development / waiting for revised SPS definition
Project 2009-03 EOP
Retires requirements from EOP-003 that map to PRC-010-1
In development / waiting for UVLS
Project 2010-05.2 SPS
Revised SPS definition revision will encompass a subset of UVLS programs currently covered by the legacy UVLS standards
Forming drafting team
April 2014
First SPS SDT Meeting
June 2014
UVLS and EOP Standards and SPS Defintion First Ballot
February 2015
UVLS and EOP Standards and SPS Definiton to BOT
April 2015
UVLS and EOP Standards and SPS Definiton Petition Package to FERC
TBD
Revised SPS Standards to BOT

Standards Announcement

Project 2010-05.2 Phase 2 of Protection Systems (Special Protection Systems) Standard Authorization Request

Informal Comment Period Now Open through March 19, 2014

Now Available

A 30-day comment period for the **Phase 2 of Protection Systems – Special Protection Systems** Standard Authorization Request is open through **8 p.m. Eastern on Wednesday, March 19, 2014.**

Instructions for Commenting

The comment period is open through **8 p.m. Eastern on Wednesday, March 19, 2014.** Please use the electronic form to submit comments on the SAR. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Individual or group. (20 Responses)
Name (11 Responses)
Organization (11 Responses)
Group Name (9 Responses)
Lead Contact (9 Responses)
Question 1 (20 Responses)
Question 1 Comments (20 Responses)
Question 2 (18 Responses)
Question 2 Comments (20 Responses)
Question 3 (0 Responses)
Question 3 Comments (20 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
The annual assessment of SPS in transmission planning studies should be addressed within Transmission Planning (TPL) standards. We recommend that Transmission Planning requirements not be included in Protection and Control (PRC) standards.
No
Individual
Anthony Jablonski
ReliabilityFirst
Yes
ReliabilityFirst agrees with the scope of the SAR and believes these revised standards will enhance reliability. Specifically a modified SPS definition will increase clarity and removal of the RRO as the applicable entity from certain standards will remove the “fill-in the blank” aspects and correctly make them enforceable on users, owners and operators of the BES.
Group
MRO NERC Standards Review Forum
Joseph DePoorter
Yes
The current draft of the SAR scope includes PRC-017 to avoid any gaps or overlap between PRC-017 and the proposed SPS standard. Since the PRC-017 standard is scheduled to be

retired with the effective date of PRC-005-2, which is April 1, 2014, PRC-005-2 already includes in its scope the maintenance and testing requirements of the Protection System elements of a SPS. Therefore there is no gap, and addressing of PRC-017 in the SPS standard creates overlap and potential double jeopardy (between PRC-005-2 and the SPS standard). It is recommended that the maintenance and testing requirements of all of the elements of the SPS be in the same standard and not split the requirements for the testing of parts of the SPS into two standards. Since the specific requirements for the testing of the "Protection System components" of a SPS are already in PRC-005, it seems to make more sense to simply make PRC-005 apply to "all" components (parts) of a SPS, rather than repeat the specific requirements for the testing in a second standard. While the NSRF understands that SPS misoperations were not addressed in the recent PRC-004 revision, the NSRF believes that SPS misoperations can be addressed under PRC-004-3 without any further significant modifications. Once the definition of a SPS is clearly determined (part of this project), the analysis of any operation (or lack of operation) of the scheme does not need to be treated any differently than other Protection System analysis and correct-operation determination. It is recommended that the evaluation of proper/improper operation of a SPS be included in PRC-004 rather than in a second Misoperation standard, PRC-016. Once the definition of a SPS is well defined, it should be no more or less difficult to determine if it operated correctly than any other protection scheme. The time frames for review, possible involvement of multiple parties, and Corrective Action Plans aspects apply directly to SPSs just as they do to ordinary Protection System schemes. The SAR scope should be expanded to include more definition of the term, “functional modification.” There will continue to be uncertainty and inconsistency regarding which SPS changes are a “functional modification” until specific criteria and examples are developed. For instance, the criteria and examples should be able to address the treatment of such changes as a direct replacement of a failed SPS component failure (e.g. SEL-321 relay for SEL-321 relay), upgrading a SEL-321 relay with a SEL-421 relay with the same logic, and using a different logic to accomplish the same system result.
No
The NRSF has concerns that the proposed SPS definition in the technical paper remains broad, lacks sufficient clarity and the specificity necessary for consistent identification / classification of SPS systems across all eight regions. While the SPCS effort is commendable, the definition remains overly broad and will continue to bring in protection systems that don’t affect the security of the BES. This is evidenced by the long list of identified exclusions. The drafting team cannot identify and exclude all possible protection schemes that respond to non-fault conditions and entities will continue to identify more systems that need to be excluded as there are many reasons to install specific protection systems. The MRO NSRF suggests that the SAR allow room for the drafting team to consider enhancements other than what is proposed in the SPCS technical paper. Perhaps a hybrid definition / screening process followed by a specific BES system instability analysis are needed to 1) clearly communicate the SPS definition intentions, and 2) identifying only BES

protection systems that are “Special” because they have a regional impact on BES security. An example is the difference between a reverse power relay that trips a backfed 100kV and greater BES bus (which should not be a special protection system), versus the SONGS scheme that helped trigger the southwest power outage (which should be special due to its security impact on the BES). The hybrid definition / screening process could start with an English SPS definition similar to what was proposed by the SPCS allowing entities to quickly screen protection systems for potential inclusions and exclusions similar to the BES definition. This could be followed by a BES security impact analysis which would screen for BES transmission instability, uncontrolled separation, and cascading using known and understood power stability program stability analyses similar to the TPL standards. This would provide repeatable concrete and measurable results that would clearly identify protection schemes that had a BES security impact. Concrete and measurable criteria could be specified using understood industry practices and IEEE papers or standards for identifying when BES security was impacted through regional undamped and poorly damped power system oscillations.
Individual
Jonathan Meyer
Idaho Power Co.
No
No
Individual
Oliver Burke
Entergy Services, Inc.
No
No
The centralized UVLS program should be considered as part of SPS.
Individual
Thomas Foltz
American Electric Power
Yes
The SAR proposes that PRC-017-0 be retired or revised, however this standard is already approved to be retired under PRC-005-2.
No

We are hopeful that the establishment of SPS “types”, as detailed in the SPCS technical report, may eliminate the need for regional variances.
We are encouraged by NERC’s willingness to pursue revision of the definition of Special Protection Systems and impacted standards.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
No
Comments: These comments are submitted on behalf of the following PPL NERC Registered Affiliates (“PPL”): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation; PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.
No
None
Group
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Wayne Johnson
Yes
The current draft of the SAR scope includes PRC-017-0. This standard is scheduled to be retired with the effective date of PRC-005-2, which is 01 Apr 2014. PRC-005-2 already includes in its scope the maintenance and testing requirements of the Protection System elements of a SPS. It is recommended that the maintenance and testing requirements of all of the elements of the SPS be in the same standard - either include the "Protection System components" and "non-Protection System components" of a SPS in PRC-005 or in PRC-017, and not split the requirements for the testing of parts of the SPS into two standards. Since the specific requirements for the testing of the "Protection System components" of a SPS are already in PRC-005, it seems to make more sense to simply make PRC-005 apply to "all" components (parts) of a SPS rather than repeat the specific requirements for the testing in a second standard. It is not clear how a SPS can have "non-Protection System components". If a component is required in the composition of a SPS to achieve the desired operablity, it seems implicit that it becomes a "Protection System component". Once the definition of a SPS is clearly determined (part of this project), the analysis of any operation (or lack of operation) of the scheme does not need to be treated any differently than other Protection System analysis and correct-operation determination. It is recommended that the evaluation of proper/improper operation of a SPS be included in PRC-004 rather than in a

second Misoperation standard, PRC-016. Once the definition of a SPS is well defined, it should be no more or less difficult to determine if it operated correctly than any other protection scheme. The time frames for review, possible involvement of multiple parties, and Corrective Action Plans aspects apply directly to SPSs just as they do to ordinary Protection System schemes.
Group
Florida Municipal Power Agency
Frank Gaffney
No
FMPA appreciates the efforts of the team and believes the definition is a significant improvement over the former definition. There are only a few comments we are making in response to this and the next two questions First is that we are of the opinion that Special Protection Systems are indeed Protection Systems as defined in the NERC Glossary, and as applicable to PRC-005-2 recently approved by FERC. The Applicability Section of PRC-005-2 at 4.2.4 reads: “Protection Systems installed as a Special Protection System (SPS) for BES reliability.” If an SPS is not a Protection System, then what is the scope of testing required in PRC-005-2 for an SPS? If an SPS is not a Protection System, should the scope of the SAR be changed to include modifications to PRC-005-2? The SDT seems to depend on: “… SPS are not limited to detecting faults or abnormal conditions and tripping affected equipment” in expressing its opinion that SPSs are not Protection Systems; however, those terms are not used in the Glossary definition of Protection Systems. There is nothing in the definition of Protection System that would eliminate SPSs from being a subset of Protection Systems. In addition, under the section “Voltage Threshold” of the paper that includes the proposed definition, the paper states: “(a)ll elements, at any voltage level, of an SPS intended to remediate performance issues on the bulk electric system (BES), or of an SPS that acts upon BES elements, should be subject to the NERC requirements.” If the SPS is not a Protection System that includes: (i) relays; (ii) communication systems; (iii) voltage and current sensing devices; (iv) dc supply; and (v) control circuits as elements of the Protection System, then to what does “all elements” refer?
No
The definition should not include brightlines. Brightlines already exist in at least two standards that would just cause confusion over what brightline to use. The CIP-002-5 standard has a Medium Risk brightline criteria 2.9 of Attachment 1 to CIP-002-5 which states: “2.9. Each Special Protection System (SPS), Remedial Action Scheme (RAS), or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.” IRO-005, R9 uses a criteria of: “… a Special Protection System that may have

an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) …" Adding another set of brightlines (for no apparent purpose contained within the standards but presumably for the convenience of three of the Regions) that conflict with these brightlines already within the standards will only bring confusion. Brightlines for SPSs shouldbe within each standard, not within the definition. If the SDT does not agree, then, at minimum, the SAR should be changed to modify CIP-002-5 and IRO-005 to align with the newly proposed brightlines. The definition is exceptionally long. By removing the categories and brighlines from the definition, it cuts the definition roughly in half.
The definition does not address automatic actions taken by an EMS, SCADA or DCS and whether that would be considered an SPS. For instance, an EMS can be programmed to perform automated switching (without human intervention) to relieve an overloaded Facility in a similar manner to an SPS designed with relays or a programmable logic controller. Would such automation cause the EMS to be an SPS and subject to PRC-005-2 requirements for testing?
Individual
Catherine Wesley
PJM Interconnection
Yes
Based on the high level information included in the SAR, PJM offers the following comments: a. Recommend a new name for the project. It is not a phase 2 of the Protection Misoperation standard effort as identified. It is a new project covering all aspects of SPSs, and the present Project numbering and project name are confusing. b. Specific to the strawman definition, for 'd' in the listing of schemes that do not constitute an SPS, the list of equipment is very discrete/specific. Please revise to be more generic because if not revised, could possibly leave out emerging technologies requiring future revision. c. For the classifications identified, they should be static in their scope, not dynamic which would result in potentially continued reevaluation of the classifications. In other words, base the SPS types on the contingency mitigated not the results of the contingency. d. PJM is reluctant to support adding the BA to the applicability of the standard since it is administrative in nature; however, understands that the BA is the source of the information (the largest generator unit in the BA area). Alternatives to making a new administrative requirement include using the data request section of the RoP (section 1600). e. The standard should not allow new permanent SPSs except for temporary installations that will eventually be removed when permanent mitigation is built or for maintenance conditions.
No
Individual
Bill Fowler
City of Tallahassee

Yes
While TAL appreciates the need for consistency among regions in regards to the classification of SPS, flexibility in this classification should be afforded the regions due to valid geographical concerns. For this reason, TAL believes the classification component of the proposed language should be independently developed from the SPS definition.
No
N/A
Individual
Karen Webb
City of Tallahassee - Electric Utility
Yes
While TAL appreciates the need for consistency among regions in regards to the classification of SPS, flexibility in this classification should be afforded the regions due to valid geographical concerns. For this reason, TAL believes the classification component of the proposed language should be independently developed from the SPS definition.
Yes
TAL believes valid geographical concerns exist among regions, and therefore some flexibility should be afforded in the classification of SPS.
Individual
Scott Langston
City of Tallahassee
Yes
While TAL appreciates the need for consistency among regions in regards to the classification of SPS, flexibility in this classification should be afforded the regions due to valid geographical concerns. For this reason, TAL believes the classification component of the proposed language should be independently developed from the SPS definition.
Yes
TAL believes valid geographical concerns exist among regions, and therefore some flexibility should be afforded in the classification of SPS.
TAL provides no comment
Group
PacifiCorp
Sandra Shaffer
No
Yes

PacifiCorp agrees with the Industry Need statement for this project and that the existing NERC Glossary of Terms definition for a Special Protection System (SPS) or Remedial Action Scheme (RAS) as used in the Western Interconnection lacks the clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions. This leads to inconsistent application of the SPS-related NERC Reliability Standards. Phase 1 of Project 2010-05.1 addresses Misoperations of Protection Systems (PRC-004-03). The implementation Plan for PRC-004-03 will require the Western Electricity Coordinating Council (WECC) to modify Regional Reliability Standard PRC-004-WECC-1 which has an attached Table, Major WECC Remedial Action Schemes (RAS). As this Project 2010-05.2 Special Protection Systems (Phase 2 of Protection Systems) is addressing all aspects of Special Protection Systems, including misoperations, NERC should instruct WECC to review the PRC-004-WECC-1 Table, Major WECC Remedial Action Schemes (RAS), and, to the extent possible, conform to NERC SPS/RAS definitions and classifications developed in Project 2010-05.2 SPS Phase 2. In addition, the purpose of WECC Criterion PRC-(012 through 014)-WECC-CRT-2 is to (1) establish a documented RAS review procedure to ensure compliance with PRC-012-0, (2) establish a RAS database per PRC-013-0, and (3) meet the Regional Reliability Organization / Reliability Assurer requirements of PRC-014-0. This regional criterion will require modification upon competition of Project 2010-05.2 SPS Phase 2, which is expected to provide a continent-wide definition and classification of SPS/RAS.
Individual
Gul Khan
Oncor Electric Delivery Company LLC
No
See response to Question 3 which addresses Oncor’s comments regarding the System Protection Control Subcommittee (SPCS) Technical Report.
No
The purpose of this SAR is stated to “develop continent-wide standards to address all aspects of SPS.” Oncor interprets this to mean regional variance is not considered.
With respect to the System Protection Control Subcommittee (SPCS) Technical Report (Report), Oncor provides the following comments. First, Oncor agrees with the proposed SPS definition and encourages the SDT to keep the following in the exclusions; Static Var Compensators (SVCs), Series/Shunt Capacitors, and Series/Shunt Reactors. Oncor believes these devices, as used today, are part of “standard” business practice. Additionally, Oncor has general concern about the SPS Operations Review Process as described on Page 23 of the Report. SPS design is based on long-range planning data provided by the Planning Authority. Tools to perform in depth real-time analysis are limited. Oncor believes that the immediate assessment of an SPS operation should be limited to considering if it operated as designed. As proposed in Appendix C of the Report, the new PRC-016 requirement which replaces PRC-012-0 R1.7, adds real time SPS operation analysis. Oncor recommends the

SDT not require this level of analysis to PRC-016 and indicate that the SPS Operations Review Process is for Mis-Operations only.
Individual
Nazra Gladu
Manitoba Hydro
Yes
(1) In the “Brief Description” section of the SAR, it is stated that the project will develop a standard to address the “periodic comprehensive SPS assessments”. Are the periodic comprehensive SPS assessments necessary given that an initial review has been completed and annual assessments of SPS have been included in the transmission planning studies?
No
(1) General comment as a reminder to the SDT, consider keeping the new standard as simple as possible and of minimum length. (2) General comment - consider replacing all instances of the word “standard” with “NERC Reliability Standard”. (3) Page 3 - capitalize the word “data” in the title for PRC-015-0 Special Protection System data and Documentation. (4) Page 3 - capitalize and re-write “bulk power system” as “Bulk-Power System”. (5) Page 3 - a ‘period’ is missing after the text “……into a Reliability Standard”.
Group
ACES Standards Collaborators
Jason Marshall
Yes
(1) In general, we are supportive of the concept of the SAR. We support developing a more specific definition of SPS for consistent application and classification of SPSs across all NERC regions. However, we do have some specific concerns identified below. (2) The SAR should clarify what is meant by “planning, coordination, and design” and “review, assessment, and documentation” of SPS. If by “planning, coordination, and design,” the SAR intends to consider which facilities the SPS will open by performing planning studies and to consider their impacts on one another in the same studies, we are supportive. If the engineering design (e.g. such as what relays will be used, what CT settings will be) is what is intended, we do not support the SAR as it is inconsistent with any other standard. For example, there is no engineering design standard for Protection Systems. This would extend the standards beyond what the original intention of the fill-in-the-blank unapproved standards. Furthermore, inclusion of “review” and “assessment” is part of the confusion because we interpret this to mean the analysis that is performed in the planning studies. Please clarify. (3) In the “Brief Description” section, what is the difference between “annual assessments of SPS in transmission planning studies” and “periodic comprehensive SPS assessments?” Annual would be periodic. Please provide clarification.
No

(1) We have no additional comments. Thank you for the opportunity to comment.
Individual
David Jendras
Ameren
Yes
(1) Will the term RAS be eliminated, such that SPS is used consistently by all eight regions? If RAS is retained then the statement “Also called Remedial Action Scheme” from the present definition also needs to be retained. (2) Is our understanding correct that the scope is to be limited to the 693 reliability standards?
No
We believe that the term ‘system’ is used in a myriad of ways in the NERC Glossary of Terms. Thus we request revising the first sentence of the proposed SPS definition from the SAMS-SPCS SPS Technical Reference to clarify ‘system’. We recommend the following: ‘A scheme designed to detect predetermined Bulk Electric System (system) conditions and automatically take corrective actions, other than the isolation of faulted elements, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading.’
Group
Bonneville Power Administration
Andrea Jessup
No
No
Group
SPP Standards Review Group
Robert Rhodes
Yes
We are concerned that the scope of this project may creep beyond the true purpose of Special Protection Systems into the area of protection schemes used for individual facilities. While we believe this is covered in the accompanying SPCS report, it is not spelled out specifically in the SAR. It needs to be included to keep the SDT on track.
No
While we realize this is a standard question on SAR postings, it seems odd that it is included in a project that is intended to pull the differing interpretations of SPS from the individual Regions into a single, continent-wide effort. This being the case, we hope that regional differences can be put aside.

We note the effort within the SPCS report to clearly state that SPS are not truly Protection Systems and an effort was made to use lower case protection systems to stay away from the conflict. This being the case, perhaps we should defer to the naming convention used in WECC and designate these systems Remedial Actions Schemes.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

Draft 1 of PRC-012-2 corrects the applicability of the fill-in-the-blank standards (PRC-012-1, PRC-013-1, PRC-014-1) by assigning the requirement responsibilities to the specific users, owners, and operators of the Bulk-Power System, and incorporates the reliability objectives of all the RAS/SPS-related standards. This draft of PRC-012-2 contains eleven (11) requirements and measures, and the associated rationale boxes and corresponding technical guidelines. There are also three (3) attachments within the draft standard incorporated via references in the requirements. This draft of PRC-012-2 does not contain “Compliance” elements such as VRFs, VSLs; they cannot be determined until requirement development is completed. PRC-012-2 is posted for a 21-day informal comment period to gather stakeholder input for use in the standards development process.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	February 12, 2014
SAR posted for comment	February 18, 2014
Standards Committee approved the SAR	June 10, 2014

Anticipated Actions	Date
Draft 1 of PRC-012-2 posted for informal comment	April 30 – May 20, 2015
45-day formal comment period with ballot	July 2015
10-day final ballot	October 2015
NERC Board (Board) adoption	November 2015

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Remedial Action Schemes
2. **Number:** PRC-012-2
3. **Purpose:** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Planner

   4.1.3. RAS-owner – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS

   4.1.4. RAS-entity – the Transmission Owner, Generator Owner, or Distribution Provider designated to represent all owners of the RAS

   4.2. Facilities:

   4.2.1. Remedial Action Schemes (RAS)

5. **Effective Date:** See Implementation Plan for Project 2010-05.3 PRC-012-2

B. Requirements and Measures

Rationale for Requirement R1: Each Remedial Action Scheme (RAS) is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES); therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification or retirement (removal from service) must be completed prior to implementation. A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality.To facilitate a review that promotes reliability, the RAS-entity must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates the RAS-entity provide them to the reviewing Reliability Coordinator (RC). The RC responsible for the review will be the RC that coordinates the area where the RAS is located. In cases where a RAS crosses multiple RC Area boundaries, each affected RC would be responsible for conducting either individual reviews or a coordinated review.

R1. Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall submit the information identified in Attachment 1 to the reviewing Reliability Coordinator(s). *[Violation Risk Factor:] [Time Horizon:]*

M1. Acceptable evidence is a copy of the Attachment 1 documentation and the dated communications with the reviewing Reliability Coordinator(s) in accordance with Requirement R1.

Rationale for Requirement R2: Requirement R2 mandates that the Reliability Coordinator (RC) perform a review of a proposed new RAS or an existing RAS proposed for functional modification or retirement (removal from service) in its RC area.

The RC is the functional entity best-suited to perform the RAS reviews because it has a wide-area perspective of reliability that includes awareness of reliability issues in its neighboring RC Areas. This wide-area purview provides continuity in the review process and better facilitates the coordination of interactions among separate RAS as well as the coordination of 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, Planning Coordinator (PC), Transmission Planner (TP), or other entity that could be involved in the planning or implementation of a RAS. The RC may designate a third party to conduct the RAS reviews; however, the RC will retain the responsibility of compliance with this requirement.

Attachment 2 of this standard is a checklist provided to the RC to assist in identifying important design and implementation aspects of RAS, and in facilitating consistent reviews for each RAS submitted. The time frame of four full calendar months is consistent with current utility practice; however, flexibility is provided by allowing the parties to negotiate a different schedule for the review.

Note: An RC may need to include this task in its reliability plan(s) for the Region(s) in which it is located.

R2. For each RAS submitted pursuant to Requirement R1, each reviewing Reliability Coordinator shall, within four full calendar months of receipt of Attachment 1 materials, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to the RAS-entity. *[Violation Risk Factor:] [Time Horizon:]*

M2. Acceptable evidence may include, but is not limited to, date-stamped reports, or other documentation detailing the RAS review, and the dated communications with the RAS-entity in accordance with Requirement R2.

Rationale for Requirement R3: Requirement R3 mandates the RAS-entity address all reliability-related issues identified by the Reliability Coordinator (RC) during the RAS review, and obtain approval from the RC that the RAS implementation can proceed. This interaction promotes reliability by minimizing the introduction of inadvertent actions (risks) to the BES. A specific time period for the RAS-entity to respond to the RC's review is not necessary because an expeditious response is in the self-interest of the RAS-owner(s) to effect a timely implementation. The review by the RC is intended to identify reliability issues that must be resolved before the RAS can be put in service. The reliability issues could involve dependability, security, or both. A more detailed explanation of dependability and security is included in the Supplemental Materials section of the standard.

R3. Following the review performed pursuant to Requirement R2, the RAS-entity shall address each identified reliability-related issue and obtain approval from each reviewing Reliability Coordinator, prior to placing a new or functionally modified RAS in-service or retiring an existing RAS. *[Violation Risk Factor:] [Time Horizon:]*

M3. Acceptable evidence may include, but is not limited to, date-stamped documentation and date-stamped communications with the reviewing Reliability Coordinator in accordance with Requirement R3.

Rationale for Requirement R4: Requirement R4 mandates that a technical evaluation of each RAS be performed at least once every 60 full calendar months. The purpose of periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as BES performance following an inadvertent RAS operation. This periodic evaluation is needed due to possible changes in system topology and operating conditions that may have occurred since the previous RAS evaluation (or initial review) was completed. Sixty (60) full calendar months was selected as the maximum time frame for the evaluation based on the time frames for similar requirements in Reliability Standards PRC-006-1, PRC-010-1, and PRC-014-1. The RAS evaluation can be performed sooner if it is determined that material changes to system topology or system operating conditions that could potentially impact the effectiveness or coordination of the RAS have occurred since the previous RAS evaluation or will occur before the next scheduled evaluation. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is adequate; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluations (Parts 4.1, 4.2, 4.3) are planning analyses which involve modeling of the interconnected transmission system; consequently, the Transmission Planner (TP) is the functional entity best qualified to perform the analyses. To promote reliability, the TP is required to provide the RAS-owner(s) and the Reliability Coordinator(s) with the results of each evaluation.

R4. Each Transmission Planner shall perform an evaluation of each RAS within its planning area at least once every 60 full calendar months and provide the RAS-owner(s) and the Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether: *[Violation Risk Factor:] [Time Horizon:]*

4.1. The RAS mitigates the System condition(s) or contingency(ies) for which it was designed.

4.2. The RAS avoids adverse interactions with other RAS, and protection and control systems.

4.3. The inadvertent operation of the RAS satisfies the same performance requirements as those required for the contingency for which it was designed or, if no performance requirements apply, the inadvertent operation of the RAS satisfies the requirements of Category P7 in Table 1 of NERC Reliability Standard TPL-001-4, or its successor.

M4. Acceptable evidence may include, but is not limited to, date-stamped reports or other documentation of the analyses comprising the evaluation(s) of each RAS and date-stamped communications with the RAS-owner(s) and the Reliability Coordinator(s) in accordance with Requirement R4.

Rationale for Requirement R5: Deficiencies identified in the periodic RAS evaluation conducted by the Transmission Planner in Requirement R4 are likely to pose a reliability risk to the BES due to the impact of either a RAS operation or incorrect operation. To avoid this reliability risk, Requirement R5 mandates that the RAS-owner(s) submit a Corrective Action Plan that establishes the mitigation methods and timetable to address the deficiency. Submitting the Corrective Action Plan to the Reliability Coordinator (RC) within six full calendar months of receipt ensures any deficiencies are adequately addressed in a timely manner. If the Corrective Action Plan requires that a functional change be made to a RAS, the RAS-owner(s) will need to submit information identified in

Attachment 1 to the RC(s) for review prior to placing RAS modifications in service per Requirement 1.

R5. Within six full calendar months of being notified of a deficiency in its RAS based on the evaluation performed pursuant to Requirement R4, each RAS-owner shall submit a Corrective Action Plan to its reviewing Reliability Coordinator(s). *[Violation Risk Factor:] [Time Horizon:]*

M5. Acceptable evidence is a date-stamped Corrective Action Plan and date-stamped communications with each reviewing Reliability Coordinator in accordance with Requirement R5.

Rationale for Requirement R6: The correct operation of a RAS is important to maintaining the reliability and integrity of the Bulk Electric System (BES). Any incorrect operation of a RAS indicates the RAS effectiveness and/or coordination has been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected should be analyzed. The 120 calendar day time frame aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation.

R6. Within 120-calendar days of each RAS operation or each failure of a RAS to operate, each RAS-owner(s) shall analyze the RAS for performance deficiencies. The analysis shall determine whether the: *[Violation Risk Factor:] [Time Horizon:]*

6.1. Power System conditions appropriately triggered the RAS.

6.2. RAS responded as designed.

6.3. RAS was effective in mitigating power System issues it was designed to address.

6.4. RAS operation resulted in any unintended or adverse power System response.

M6. Acceptable evidence may include, but is not limited to, date-stamped documentation detailing the RAS operational analysis in accordance with Requirement R6.

Rationale for Requirement R7: Performance deficiencies identified in the analysis conducted by the RAS-owner(s), pursuant to Requirement R6, are likely to pose a reliability risk to the BES. To avoid this reliability risk, Requirement R7 mandates that the RAS-owner(s) submit a Corrective Action Plan that establishes the mitigation methods and timetable to address the deficiency. Submitting the Corrective Action Plan to the Reliability Coordinator (RC) within six full calendar months of receipt ensures any deficiencies are adequately addressed in a timely manner. If the Corrective Action Plan requires that a functional change be made to a RAS, the RAS-owner(s) will need to submit information identified in Attachment 1 to the RC(s) for review prior to placing RAS modifications in service per Requirement 1.

R7. Within six full calendar months of identifying a performance deficiency in its RAS based on the analysis performed pursuant to Requirement R6, each RAS-owner shall submit a Corrective Action Plan to its reviewing Reliability Coordinator(s). *[Violation Risk Factor:] [Time Horizon:]*

M7. Acceptable evidence is a date-stamped Corrective Action Plan and date-stamped communications with the reviewing Reliability Coordinator(s) in accordance with Requirement R7.

Rationale for Requirement R8: Requirement R8 mandates the RAS-owner(s) implement a Corrective Action Plan submitted to address any identified deficiency(ies) found in conjunction with the periodic evaluation pursuant to Requirement R4, and any identified incorrect operation found by the analysis of an actual RAS operation pursuant to Requirement R6. Implementing the Corrective Action Plan (CAP) submitted pursuant to either Requirement R5 or Requirement R7 ensures that any identified deficiency(ies) or incorrect operation(s) are addressed in a timely manner. The CAP identifies the work (corrective actions) as well as the work schedule (the time frame within which the corrective actions are to be taken).

R8. For each CAP submitted pursuant to Requirement R5 and Requirement R7, each RAS-owner shall implement the CAP. *[Violation Risk Factor:] [Time Horizon:]*

M8. Acceptable evidence may include, but is not limited to, dated documentation (electronic or hardcopy format) such as work management program records, work orders, and maintenance records that document the implementation of a CAP in accordance with Requirement R8.

Rationale for Requirement R9: Due to the wide variety of RAS designs and implementations, and the potential for impacing BES reliability, it is important that periodic functional testing of RAS is performed. A functional test provides an overall confirmation of the RAS's ability to operate as designed and verifies the proper operation of the non-Protection System (control) components of a RAS that are not addressed in PRC-005. Protection System components that are part of a RAS are maintained in accordance with PRC-005. The six calendar year interval was chosen to coincide with the maintenance intervals of various Protection System and Automatic Reclosing components established in PRC-005-3. The RAS-owner is in the best position to determine the testing procedure and schedule due to its overall knowledge of the RAS design, installation, and expected operation. Periodic functional testing promotes the identification of changes in System infrastructure that could have introduced latent failures into the RAS. Functional testing is not synonymous with end-to-end testing. Each segment of a RAS should be tested but the segments can be tested individually negating the need for complex maintenance schedules.

R9. At least once every six calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. *[Violation Risk Factor:] [Time Horizon:]*

M9. Acceptable evidence may include, but is not limited to, date-stamped documentation of the functional testing.

Rationale for Requirement R10: The RAS database is a comprehensive record of all RAS existing in a Reliability Coordinator's area. The database enables the RC to provide other entities with a reliability need the ability to attain high level information on existing RAS that potentially impact the entities' operational and/or planning activities. Attachment 3 lists the minimum information required for the RAS database. This information allows an entity to evaluate the need for requesting more detailed information (e.g., modeling information - Requirement R11) from the RAS-entity. The Reliability Coordinator (RC) is the appropriate entity to maintain the database because the RC receives the required database information when a new or modified RAS is submitted for review.

R10. Each Reliability Coordinator shall maintain a RAS database containing the information in Attachment 3. *[Violation Risk Factor:] [Time Horizon:]*

M10. Acceptable evidence may include, but is not limited to, date-stamped spreadsheets, database reports, or other documentation demonstrating a RAS database was maintained in accordance with Requirement R10.

Rationale for Requirement R11: Other registered entities may have a reliability-related need for modeling RAS operations and will require additional information beyond what is listed in Attachment 3. Such information may be needed to address one or more of the following reliability-related needs:

- Periodic RAS evaluations
- Planning assessment studies
- Operations planning and/or real-time analyses
- BES event analyses
- Coordination of RAS among entities

Requirement R11 mandates that each RAS-entity provide the requester with either the detailed information required to model a RAS, or a written response specifying the basis for denying the request. Thirty (30) calendar days is a reasonable amount of time for each RAS-entity to respond to a request.

R11. Within 30 calendar days of receiving a written request from a registered entity with a reliability-related need to model RAS operation, each RAS-entity shall provide the requesting entity with either the requested information or a written response specifying the basis for denying the request. *[Violation Risk Factor:] [Time Horizon:]*

M11. Acceptable evidence may include, but is not limited to, date-stamped communications e.g. emails, letters, or other documentation demonstrating that the RAS-entity either provided the information to model RAS operation or provided a written response specifying the basis for denying the request in accordance with Requirement R11.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable entity shall keep data or evidence to show compliance with requirements **(DELETE GREEN TEXT PRIOR TO PUBLISHING) Add requirements as appropriate for this standard. This section is only for those requirements that do not have the default data retention.** since the last audit.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.				
R2.				
R3.				

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents. **(DELETE GREEN TEXT PRIOR TO PUBLISHING) A link should be added to the implementation plan and other important documents associated with the standard once finalized.**

Version History **(DELETE GREEN TEXT PRIOR TO PUBLISHING) Note: All version histories' content should be carried over to next generation.**

Version	Date	Action	Change Tracking
		(DELETE GREEN TEXT PRIOR TO PUBLISHING) Project #: action completed	**(DELETE GREEN TEXT PRIOR TO PUBLISHING) New, Errata, Revisions, Addition, Interpretation, etc.**

Attachment 1
Supporting Documentation for RAS Review

The following checklist identifies important RAS information for each new or functionally modified[1] RAS that the RAS-entity shall document and provide to the Reliability Coordinator for review pursuant to Requirement R1. When a RAS has been previously reviewed, only the proposed modifications to that RAS require review; however, it will be helpful to the reviewers if the RAS entity provides a summary of the previously approved functionality.

I. General

- ❑ Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.

- ❑ Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.

- ❑ The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP.
  [Reference NERC Reliability Standard PRC-012, Requirements R5 and R7]

II. Functional Description and Transmission Planning Information

- ❑ Contingencies and system conditions that the RAS is intended to remedy.
  [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.1]

- ❑ The actions to be taken by the RAS in response to disturbance conditions.
  [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.2]

- ❑ A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies should include information such as the study year(s), system conditions, and contingencies analyzed on which the RAS design is based, and when those technical studies were performed.
  [Reference NERC Reliability Standard PRC-014, R3.2]

- ❑ Information regarding any future system plans that will impact the RAS.
  [Reference NERC Reliability Standard PRC-014, R3.2]

- ❑ Documentation showing that inadvertent operation of the RAS satisfies the same performance requirements as those required for the contingency for which it was designed. For RAS that are installed for conditions or contingencies for which there are no applicable System performance requirements, demonstrate that the inadvertent operation satisfies the System performance requirements of Table 1, Category P7 of NERC Reliability Standard TPL-001-4 or its successor.
  [Reference NERC Reliability Standard PRC-012, R1.4]

[1]Functionally Modified:
Any modification to a RAS beyond the replacement of components that preserve the original functionality is a functional modification.

- ❑ An evaluation indicating that the RAS avoids adverse interactions with other RAS, and protection and control systems.
  [Reference NERC Reliability Standards PRC-012, R1.5 and PRC-014, R3.4]

- ❑ Identification of other affected RCs.

III. Implementation

- ❑ Documentation describing the equipment used for detection, telecommunications, transfer trip, logic processing, and monitoring, whichever are applicable.

- ❑ Information on detection logic and settings/parameters that control the operation of the RAS. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.3]

- ❑ Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in service or is being maintained.

- ❑ Documentation showing that an appropriate level of redundancy is provided such that a single RAS component failure, when the RAS is intended to operate, does not prevent the interconnected transmission system from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the System events and conditions for which the RAS was designed. The documentation should describe or illustrate how the implementation design achieves this objective.
  [Reference NERC Reliability Standard PRC-012, R1.3]

- ❑ Documentation describing the functional testing process.

RAS Retirement

The following checklist identifies important RAS information for each existing RAS to be retired that the RAS-entity shall document and provide to the Reliability Coordinator for review pursuant to Requirement R1.

- ❑ Information necessary to ensure that the Reliability Coordinator is able to understand the physical and electrical location of the RAS and related facilities.

- ❑ A summary of technical studies, if applicable, upon which the decision to retire the RAS is based.

- ❑ Anticipated date of RAS retirement.

Attachment 2
Reliability Coordinator RAS Review Checklist

The following checklist identifies important reliability related considerations for the Reliability Coordinator to review and verify for each new or functionally modified[2] RAS. The RC review is not limited to the checklist items and the RC may request additional information on any reliability issue related to the RAS.

<u>Determination of Review Level</u>

RAS can have varying impacts on the power System. RAS with more significant impact require a higher level of review than those having a lesser impact. The level of review by the RC may be limited if the System response for a failure of the RAS to operate or inadvertent operation of the RAS could not result in any of the following conditions:

- frequency-related instability
- unplanned tripping of load or generation
- uncontrolled separation or cascading outages

If any of the conditions above may be produced, the entire review checklist below should be followed.

RAS retirement reviews may use an abbreviated format that concentrates on the Planning justifications describing why the RAS is no longer needed. Implementation issues will seldom require removal review.

<u>DESIGN</u>

- ❑ The RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to mitigate.
- ❑ The RAS arming conditions, if applicable, are appropriate to its System performance objectives.
- ❑ The RAS avoids adverse interactions with other RAS, protection systems, control systems, and operating procedures.
- ❑ The effects of RAS incorrect operation, including inadvertent operation and failure to operate (if non-operation for RAS single component failure is acceptable), have been identified.
- ❑ The inadvertent operation of the RAS satisfies the same performance requirements as those required for the contingency for which it was designed. For RAS that are installed for conditions or contingencies for which there are no applicable System performance requirements, the inadvertent operation satisfies the System performance requirements of Table 1, Category P7 of NERC Reliability Standard TPL-001-4 or its successor.

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[2] Functionally Modified:
Any modification to a RAS beyond the replacement of components that preserve the original functionality is a functional modification.

- The effects of future System plans on the design and operation of the RAS, where applicable, have been identified.

IMPLEMENTATION

- The implementation of RAS logic appropriately correlates desired actions (outputs) with System events and conditions (inputs).
- The timing of RAS actions is appropriate to its System performance objectives.
- A single component failure in a RAS does not prevent the BES from meeting the same performance requirements as those required for the System events and conditions for which the RAS was designed.
- The RAS design facilitates periodic testing and maintenance.
- The mechanism or procedure by which the RAS is armed is clearly described, and is appropriate for reliable arming and operation of the RAS for the System conditions and events for which it is designed to operate.
- RAS automatic arming, if applicable, has the same degree of redundancy as the RAS itself.

Attachment 3
Database Information

1. RAS name
2. RAS-entity and contact information
3. Expected or actual in-service date; most recent (Requirement R2) review date; 5-year (Requirement R4) evaluation date; and, date of retirement, if applicable
4. System performance issue or reason for installing the RAS (*e.g.*, thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery)
5. Description of the contingencies or System conditions for which the RAS was designed (initiating conditions)
6. Corrective action taken by the RAS
7. Any additional explanation relevant to high level understanding of the RAS

Requirement R1:

Each Remedial Action Scheme (RAS) is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES); therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification or retirement (removal from service) must be completed prior to implementation. A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality.To facilitate a review that promotes reliability, the RAS-entity must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates the RAS-entity provide them to the reviewing Reliability Coordinator (RC). The RC responsible for the review will be the RC that coordinates the area where the RAS is located. In cases where a RAS crosses multiple RC Area boundaries, each affected RC would be responsible for conducting either individual reviews or a coordinated review.

Requirement R2:

Requirement R2 mandates that the Reliability Coordinator (RC) perform a review of a proposed new RAS or an existing RAS proposed for functional modification or retirement (removal from service) in its RC area.

The RC is the functional entity best-suited to perform the RAS reviews because it has a wide-area perspective of reliability that includes awareness of reliability issues in its neighboring RC Areas. This wide-area purview provides continuity in the review process and better facilitates the coordination of interactions among separate RAS as well as the coordination of 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, Planning Coordinator (PC), Transmission Planner (TP), or other entity that could be involved in the planning or implementation of a RAS. The RC may designate a third party to conduct the RAS reviews; however, the RC will retain the responsibility of compliance with this requirement.

Attachment 2 of this standard is a checklist provided to the RC to assist in identifying important design and implementation aspects of RAS, and in facilitating consistent reviews for each RAS submitted. The time frame of four full calendar months is consistent with current utility practice; however, flexibility is provided by allowing the parties to negotiate a different schedule for the review.

Note: An RC may need to include this task in its reliability plan(s) for the Region(s) in which it is located

Requirement R3:

Requirement R3 mandates the RAS-entity address all reliability-related issues identified by the Reliability Coordinator (RC) during the RAS review, and obtain approval from the RC that the RAS implementation can proceed. This interaction promotes reliability by minimizing the introduction of inadvertent actions (risks) to the BES. A specific time period for the RAS-entity to respond to the RC's review is not necessary because an expeditious response is in the self-interest of the RAS-owner(s) to effect a timely implementation. The review by the RC is intended to identify reliability issues that must be resolved before the RAS can be put in service. The reliability issues could involve dependability, security, or both.

Dependability is a component of reliability and is the measure of a device's certainty to operate when required. Since RAS are usually installed to meet performance requirements of NERC standards, a failure of the RAS to operate when intended would put the System at risk of violating NERC performance standards if the critical contingency(ies) or System conditions occur. This risk is usually mitigated by installing an appropriate level of redundancy as part of the RAS so that it will still accomplish its intended purpose even while experiencing a single component failure.

Security is a component of reliability and is the measure of a device's certainty not to operate falsely. False, or inadvertent operation of a RAS results in taking some programmed action that the RAS would take for a correct operation, but without either the appropriate arming conditions or occurrence of the critical contingency(ies) or System conditions expected to trigger the RAS action. Typically these actions include shedding load or generation or re-configuring the System. This inadvertent action is undesirable in the absence of the critical System conditions and may, on its own, put the System in a less secure state. The standard allows an impact up to the level that would occur for a correct operation. If this risk needs to be further mitigated, voting schemes have been successfully used in the industry for both RAS and Protection systems.

Either type of reliability issue must be resolved before placing the RAS in service to avoid placing the System at unacceptable risk. The RAS-entity (and any other RAS-owner) or the RC may have alternative ideas or methods available to resolve the issue(s). In either case, the concern needs to be resolved in favor of reliability, and the RC has the final decision.

Requirement R4:

Requirement R4 mandates that a technical evaluation of each RAS be performed at least once every 60 full calendar months. The purpose of periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as BES performance following an inadvertent RAS operation. This periodic evaluation is needed due to possible changes in system topology and operating conditions that may have occurred since the previous RAS evaluation (or initial review) was completed. Sixty (60) full calendar months was selected as the maximum time frame for the evaluation based on the time frames for similar requirements in Reliability Standards PRC-006-1, PRC-010-1, and PRC-014-1. The RAS evaluation can be performed sooner if it is determined that material changes to system topology or system operating conditions that could potentially impact the effectiveness or coordination of the RAS have occurred since the previous RAS evaluation or will occur before the next scheduled evaluation. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is adequate; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluations (Parts 4.1, 4.2, 4.3) are planning analyses which involve modeling of the interconnected transmission system; consequently, the Transmission Planner (TP) is the functional entity best qualified to perform the analyses. To promote reliability, the TP is required to provide the RAS-owner(s) and the Reliability Coordinator(s) with the results of each evaluation.

Part 4.3 requires that the inadvertent operation of the RAS meet the same requirements as those required for the contingency(ies) or System conditions for which it was installed. So if the RAS was designed to meet one of the Planning Events (P0-P7) in TPL-001-4, then the inadvertent operation of the RAS must meet the same performance requirements listed in the standard for that planning event. Part 4.3 also requires that the inadvertent operation of the RAS installed for an Extreme Event in TPL-001-4 or for some other contingency or System condition not defined in TPL-001-4 (therefore without performance requirements), meet the minimum System performance requirements of Category P7 in Table 1 of NERC Reliability Standard TPL-001-4, or its successor. These would include requirements such as the System shall remain stable, cascading and uncontrolled islanding shall not occur, applicable Facility Ratings shall not be exceeded, System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits, transient voltage responses shall be within acceptable limits.

Requirement R5:

Deficiencies identified in the periodic RAS evaluation conducted by the Transmission Planner in Requirement R4 are likely to pose a reliability risk to the BES due to the impact of either a RAS operation or incorrect operation. To avoid this reliability risk, Requirement R5 mandates that the RAS-owner(s) submit a Corrective Action Plan that establishes the mitigation methods and timetable to address the deficiency. Submitting the Corrective Action Plan to the Reliability Coordinator (RC) within six full calendar months of receipt ensures any deficiencies are adequately addressed in a timely manner. If the Corrective Action Plan requires that a functional change be made to a RAS, the RAS-owner(s) will need to submit information identified in Attachment 1 to the RC(s) for review prior to placing RAS modifications in service per Requirement 1.

Requirement R6:

The correct operation of a RAS is important to maintaining the reliability and integrity of the Bulk Electric System (BES). Any incorrect operation of a RAS indicates the RAS effectiveness and/or coordination has been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected should be analyzed. The purpose of the analysis is to determine whether the RAS operation was appropriately triggered; whether the RAS functioned as designed; whether the RAS actions were effective in producing the intended System response; and whether the RAS operation or non-operation resulted in any unintended or adverse System response. The 120 calendar day time frame aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation.

Requirement R7:

Performance deficiencies identified in the analysis conducted by the RAS-owner(s), pursuant to Requirement R6, are likely to pose a reliability risk to the BES. To avoid this reliability risk, Requirement R7 mandates that the RAS-owner(s) submit a Corrective Action Plan that establishes the mitigation methods and timetable to address the deficiency. Submitting the Corrective Action Plan to the Reliability Coordinator (RC) within six full calendar months of receipt ensures any deficiencies are adequately addressed in a timely manner. If the Corrective Action Plan requires that a functional change be made to a RAS, the RAS-owner(s) will need to submit information identified in Attachment 1 to the RC(s) for review prior to placing RAS modifications in service per Requirement 1.

Requirement R8:

Requirement R8 mandates the RAS-owner(s) implement a Corrective Action Plan submitted to address any identified deficiency(ies) found in conjunction with the periodic evaluation pursuant to Requirement R4, and any identified incorrect operation found by the analysis of an actual RAS operation pursuant to Requirement R6. Implementing the Corrective Action Plan (CAP) submitted pursuant to either Requirement R5 or Requirement R7 ensures that any identified deficiency(ies) or incorrect operation(s) are addressed in a timely manner. The CAP identifies the work (corrective actions) as well as the work schedule (the time frame within which the corrective actions are to be taken).

A Corrective Action Plan (CAP) documents a RAS performance deficiency, the strategy to correct the deficiency with identified tasks, the responsible party assigned to each task, and the targeted completion date(s).

The following are examples situations of when a CAP is required:

a) A determination after a RAS operation/non-operation investigation that the RAS did not meet performance expectations. The RAS did not operate as designed.
b) Periodic planning assessment reveals RAS changes are necessary to satisfy performance effectiveness or to correct identified coordination issues.
c) Equipment failure detrimentally affects the dependability or security of the RAS.

Requirement R9:

The reliability objective of Requirement R9 is to test the non-Protection System components of a RAS (controllers such as PLCs) and to verify the overall performance of the RAS through functional testing. Functional tests validate RAS operation by ensuring system states are detected and processed, and that actions taken by the controls are correct and within the expected time frames using the in-service settings and logic.

Functional testing can be difficult to schedule and perform, but it is critical to ensure the proper functioning of RAS and the resulting BES reliability. Since the functional test operates the RAS under controlled conditions with known System states and expected results, testing and result analysis can be performed without impact to the BES. The RAS-owner is in the best position to determine the testing procedure and schedule due to their overall knowledge of the RAS design, installation, and expected operation. Periodic functional testing provides the RAS-owner assurance that latent failures are not present in the RAS design and implementation, and also promotes identification of changes in System infrastructure could have introduced latent failures. The six calendar year interval was chosen to coincide with the maintenance intervals of various Protection System and Automatic Reclosing components established in PRC-005-3.

Functional testing is not synonymous with end-to-end testing. Each segment of a RAS should be tested but the segments can be tested individually negating the need for complex maintenance schedules. If System conditions do not allow a complete end-to-end system test or a RAS is implemented across many locations and uses a wide variety of components, functional testing of small zones within a larger RAS, such that all controls in overlapping zones are tested over time constitute an acceptable functional testing approach. The goal of the functional test procedure is inclusion of all conditions the RAS uses for detection, arming, operating, and data collection that will address the System condition(s) for which the RAS is designed.

As an example, consider a RAS implemented using one control component not addressed in the Protection System definition but used regularly in RAS: a programmable logic controller (PLC). The PLC does not meet the definition of a Protection System and will have no required maintenance as part of PRC-005. In this simplified example, the PLC based RAS is sensing System conditions such as loading and line status from many locations, and implements breaker tripping at multiple locations to alleviate an overload condition. At one of these locations, a line protective relay, included in a RAS-owner's Protection System Maintenance Plan as a Protection System component, is used to operate a breaker upon receipt an operate command from the remote RAS PLC. The relay sends data and receives commands from the RAS PLC over non-Protection System communications infrastructure. A functional test would simulate via external signals to the PLC system conditions requiring an operate command to the protective relay, operating its associated breaker. This action verifies RAS action, verifies PLC control logic, and verifies the RAS communications from the PLC to the relay. To complete this portion of a functional test, application of external testing signals to the protective relay, verified at the PLC are necessary to confirm full functioning of the RAS zone being tested. In this example the RAS is implemented across several locations, and the testing described would only constitute one zone of a full RAS functional test. The remaining zones based on the RAS design would also require testing.

IEEE C37.233, "IEEE Guide for Power System Protection Testing," section 8 (particularly 8.3-8.5), provides a very good overview of functional testing. The following opens section 8.3:

> "Proper implementation requires a well-defined and coordinated test plan for performance evaluation of the overall system during agreed maintenance intervals. The maintenance test plan, also referred to as functional system testing, should include inputs, outputs, communication, logic, and throughput timing tests. The functional tests are generally not component-level testing, rather overall system testing. Some of the input tests may need to be done ahead of overall system testing to the extent that the tests affect the overall performance. The test coordinator or coordinators need to have full knowledge of the intent of the scheme, isolation points, simulation scenarios, and restoration to normal procedures.

> The concept is to validate the overall performance of the scheme, including the logic where applicable, to validate the overall throughput times against system modeling for different types of contingencies, and to verify scheme performance as well as the inputs and outputs."

Requirement R10:

The RAS database is a comprehensive record of all RAS existing in a Reliability Coordinator's area. The database enables the RC to provide other entities with a reliability need the ability to attain high level information on existing RAS that potentially impact the entities' operational and/or planning activities. Attachment 3 lists the minimum information required for the RAS database. This information allows an entity to evaluate the need for requesting more detailed information (e.g., modeling information - Requirement R11) from the RAS-entity. The Reliability Coordinator (RC) is the appropriate entity to maintain the database because the RC receives the required database information when a new or modified RAS is submitted for review.

Requirement R11:

Other registered entities may have a reliability-related need for modeling RAS operations and will require additional information beyond what is listed in Attachment 3. Such information may be needed to address one or more of the following reliability-related needs:

- Periodic RAS evaluations
- Planning assessment studies
- Operations planning and/or real-time analyses
- BES event analyses
- Coordination of RAS among entities

Requirement R11 mandates that each RAS-entity provide the requester with either the detailed information required to model a RAS, or a written response specifying the basis for denying the request. Thirty (30) calendar days is a reasonable amount of time for each RAS-entity to respond to a request.

Technical Justifications for Attachment 1 Content
Supporting Documentation for RAS Review

To perform an adequate review of the expected reliability implications of a remedial action scheme (RAS) it is necessary for the RAS owner(s) to provide a detailed list of information describing the RAS to the reviewing Reliability Coordinator (RC). While information may be needed from all owners of a RAS, a single RAS-owner (designated as the (RAS-entity)) is usually assigned the responsibility of compiling the RAS data and presenting it to the RC(s) review team. Other RAS-owners may participate in the review, if they choose.

The necessary data ranges from a general overview of the scheme to results of Transmission Planning studies that illustrate System performance before and after the RAS goes into service, as well as expected performance for unusual conditions, and whether certain adverse reliability impacts may occur. Possible adverse interactions, i.e. coordination between the RAS and other RAS and protection and control systems will be examined. This review can include wide ranging electrical design issues involving the specific hardware, logic, telecommunications and other relevant equipment and controls that make up the RAS.

Attachment 1

The following checklist identifies important RAS information for each new or functionally modified[3] RAS that the RAS-entity shall document and provide to the Reliability Coordinator (RC) for review pursuant to Requirement R1. When a RAS has been previously reviewed, only the proposed modifications to that RAS require review; however, it will be helpful to the reviewers if the RAS entity provides a summary of the previously approved RAS functionality.

I. General

- ❑ Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.
    - o Provide a description of the RAS to give an overall understanding of the functionality and a map showing the location of the RAS. Identify other protection and control systems requiring coordination with the RAS. See “RAS Design”, below, for additional information.
    - o Provide a single line drawing(s) showing all sites involved. The drawing(s) should provide sufficient information to allow the RC review team to assess design reliability, and should include information such as the bus arrangement, circuit breakers, the associated switches, etc. For each site, indicate whether detection, logic, action, or a combination of these is present.
- ❑ Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.

[3]Functionally Modified:
Any modification to a RAS beyond the replacement of components that preserve the original functionality is a functional modification.

- The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP.
  [Reference NERC Reliability Standard PRC-012-2, Requirements R5 and R7]
  - The CAP is required if the periodic evaluation pursuant to Requirement R4, or the analysis of an actual RAS operation pursuant to Requirement R6 identified any performance deficieny(ies).

II. Functional Description and Transmission Planning Information

- Contingencies and system conditions that the RAS is intended to remedy.
  [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.1]
  - The System conditions which would result if no RAS action occurred should be identified.
  - Include a description of the System conditions which should arm the RAS so as to be ready to take action upon subsequent occurrence of the critical system contingencies or other operating conditions when RAS action is intended to occur. If no arming conditions are required, this should also be stated.
  - Event based RAS are triggered by specific contingencies that initiate mitigating action. These contingencies should be identified. Condition based RAS may also be initiated by specific contingencies, but this is not always required.

- The actions to be taken by the RAS in response to disturbance conditions.
  [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.2]
  - Mitigating actions are designed to result in acceptable System performance. These actions should be identified, including any time constraints and/or “backup” mitigating measures that may be required in case of a single RAS component failure.

- A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies should include information such as the study year(s), system conditions, and contingencies analyzed on which the RAS design is based, and when those technical studies were performed.
  [Reference NEC Reliability Standard PRC-014, R3.2]
  - Review the scheme purpose and impact to ensure it is (still) necessary, serves the intended purposes, and meets current performance requirements.

- Information regarding any future system plans that will impact the RAS.
  [Reference NERC Reliability Standard PRC-014, R3.2]
  - The RC’s other responsibilities under the NERC Reliability Standards focus on the Operating Horizon, rather than the Planning Horizon. As such, the RC is less likely to be aware of any longer range Plans that may have an impact on the proposed RAS. Such knowledge of future Plans is helpful to provide perspective on the capabilities of the RAS.

- Documentation showing that inadvertent operation of the RAS satisfies the same performance requirements as those required for the contingency for which it was designed or, if no performance requirements apply, the inadvertent operation of the RAS satisfies the requirements of Category P7 in Table 1 of NERC Reliability Standard TPL-001-4, or its successor.

[Reference NERC Reliability Standard PRC-012, R1.4]

- An evaluation indicating that the RAS avoids adverse interactions with other RAS, and protection and control systems.
  [Reference NERC Reliability Standards PRC-012, R1.5 and PRC-014, R3.4]
  - RAS are complex schemes that typically take action which trips load or generation or re-configures the system. Many RAS depend on sensing specific system configurations to determine whether they need to arm or take actions. Examples include: overlapping actions among RAS that may have the potential to result in cascading, unless coordinated, RAS that reconfigure the System also change the available fault duty, which can affect distance relay overcurrent ("fault detector") supervision and ground overcurrent protection coordination.

- Identification of other affected RCs.
  - This information is needed to aid in information exchange among all affected entities and coordination of the RAS with other RAS and protection and control systems.

III. Implementation

- Documentation describing the equipment used for detection, telecommunications, transfer trip, logic processing, and monitoring, whichever are applicable.

  Logic Processing
  - All RAS require some form of logic processing to determine the action to take when the scheme is triggered. Required actions are always scheme dependent. Different actions may be required at different arming levels or for different contingencies. Scheme logic may be achievable by something as simple as wiring a few auxiliary relay contacts or by much more complex logic processing.

  - Platforms that have been used reliably and successfully, include programmable logic controllers (PLCs) in various forms, personal computers (PCs), microprocessor protective relays, remote terminal units (RTUs), and logic processors. Single-function relays have been used historically to implement RAS, but this approach is now less common except for very simple new RAS or minor additions to existing RAS.

  Communications Channels
  - Communication channels used for sending and receiving RAS information between sites and/or transfer trip devices must meet at least the same criteria as for other relaying protection communication channels. Discuss performance of any non-deterministic communication systems used (such as Ethernet).

  - The scheme logic should be designed so that loss of the channel, noise, or other channel failure will not result in a false operation of the scheme.

  - It is highly desirable that the channel equipment and communications media (power line carrier, microwave, optical fiber, etc.) be owned and maintained by the RAS owner, or perhaps leased from another entity familiar with the necessary reliability requirements. All channel equipment must be monitored and alarmed to the dispatch center so that timely diagnostic and repair action shall be taken place upon failure.

- o Communication channels shall be well labeled or identified so that the personnel working on the channel can readily identify the proper circuit. Channels between entities shall be identified with a common name at all terminals.

- ❑ Information on detection logic and settings/parameters that control the operation of the RAS. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.3]

  Detection and initiating devices must be designed to be as secure as possible. The following discussion identifies several types of devices that have been used as disturbance detectors:

  - Line open status (event detectors),
  - Protective relay inputs and outputs (event and parameter detectors),
  - Transducer and IED (analog) inputs (parameter and response detectors),
  - Rate of change (parameter and response detectors).

  Several methods to determine line open status are in common use, often in combination:

  - Auxiliary switch contacts from circuit breakers and disconnect switches (52b, 89b),
  - Undercurrent detection (a low level indicates an outage),
  - Breaker trip bus monitoring, and
  - Other detectors such as angle, voltage, power, frequency, rate of change of these, out of step, etc.

- ❑ Documentation showing that any device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in service or is being maintained.

  - o In this context, a multifunction device (e.g. microprocessor-based relay) is a single device that is used to perform the function of a RAS in addition to protective relaying and/or SCADA simultaneously. It is important that other applications in the multifunction device do not compromise the functionality of the RAS when the device is in service or when is being maintained. The following list outlines concerns to be addressed when the RAS function is applied in the same microprocessor-based relay as the protection function:

    - ▪ a) Describe how the multifunction device is applied in the RAS.
    - ▪ b) Show the general arrangement and describe how the multi-function device is labeled in the design and application, so as to identify the RAS and other device functions.
    - ▪ c) Describe the procedures used to isolate the RAS function from other functions in the device.

  - d) Describe the procedures used when each multifunction device is removed from service and whether any other coordination with other protection is required.
  - e) Describe how each multifunction device is tested, both for commissioning and during periodic maintenance testing, with regard to each function of the device.
  - f) Describe how overall periodic RAS functional and throughput tests are performed if multifunction devices are used for both local protection and RAS.
  - g) Describe how upgrades to the multifunction device, such as firmware upgrades, are accomplished. How is the RAS function taken into consideration?

- Other devices usually not considered multifunction devices such as auxiliary relays, control switches, and instrument transformers may serve multiple purposes such as protection and RAS. Similar concerns apply for these applications as noted above.

- ❑ Documentation showing that a single component failure in a RAS does not prevent the BES from meeting the same performance requirements as those required for the System events and conditions for which the RAS was designed. The documentation should describe or illustrate how the implementation design achieves this objective.
  [Reference NERC Reliability Standard PRC-012, R1.3]

The critical part of PRC-012 R1.3 philosophy is that a RAS should be designed so that a "single [RAS] component failure … does not prevent … meeting the performance requirements defined in Reliability Standards". The philosophy regarding "single component failure" from PRC-012-0 is carried over in to this standard. Redundancy is one way to implement the "single component failure" philosophy but other methods are acceptable.

The following list are examples of RAS components that could be considered in the single component failure analysis:

- Any single ac secondary current or voltage source and/or related inputs to the RAS.
- Any single device used to measure electrical quantities used by the RAS.
- Any single communication channel and/or any single piece of related communication equipment used by the RAS.
- Any single computer or programmable logic device used to analyze information and provide RAS operational output.
- Any single element of the dc control circuitry that is used for the RAS, including breaker closing circuits.
- Any single auxiliary relay or auxiliary device used by the RAS.
- Any single breaker trip coil for any breaker operated by the RAS.
- Any single station battery or single charger, or other single dc source, where central monitoring is not provided for both low voltage and battery open conditions.

Duplication of the listed components is a way to achieve redundancy and meet the "single component failure" requirement. For schemes performing distributed actions (e.g. load shedding or generation rejection at multiple locations), over arming (providing extra corrective action to cover failure to operate of one critical component) can also be an effective option, as long as it does not compromise the performance of the system. Other coordinated Protection Systems, such as breaker failure, may be used as long as the System performance resulting from breaker failure is still acceptable under the original contingency the RAS was designed to mitigate

RAS Retirement

The following checklist identifies important RAS information for each existing RAS to be retired that the RAS-entity shall document and provide to the Reliability Coordinator for review pursuant to Requirement R1.

- ❑ Information necessary to ensure that the Reliability Coordinator is able to understand the physical and electrical location of the RAS and related facilities.
- ❑ A summary of technical studies, if applicable, upon which the decision to retire the RAS is based.
- ❑ Anticipated date of RAS retirement.

Technical Justifications for Attachment 3 Content
Database Information

Attachment 3 contains the minimum information the RC must consolidate into its database for each RAS in its area.

1. RAS name
   - The usual name used to identify the RAS.

2. RAS-entity and contact information
   - A reliable phone number or email address should be included to contact the RAS-entity if more information is needed (e.g. modeling information per requirement R11). At a minimum, the name of the RAS-entity responsible for the RAS information.

3. Expected or actual in-service date; most recent (Requirement R2) review date; 5-year (Requirement R4) evaluation date; and, date of retirement, if applicable
   - Specify each applicable date.

4. System performance issue or reason for installing the RAS (*e.g.*, thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery)
   - A short description of the reason for installing the RAS is sufficient, as long as the main system issues addressed by the RAS can be identify by someone with a reliablilty need.

5. Description of the contingencies or System conditions for which the RAS was designed (initiating conditions)
   - A high level summary of the conditions/contingencies is expected. Not all combinations of conditions are required to be listed.

6. Corrective action taken by the RAS
   - For schemes shedding load or generation, the maximum amount of MW should be included.

7. Any additional explanation relevant to high level understanding of the RAS
   - If deemed necessary, any additional information can be included in this section, but is not mandatory.

Unofficial Comment Form

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS) PRC-012-2

DO NOT use this form for submitting comments. Use the electronic form to submit comments on draft 1 of **PRC-012-2 – Remedial Action Schemes**. The electronic comment form must be submitted by **8 p.m. Eastern, Wednesday, May 20, 2015.**

For this informal posting, the drafting team is soliciting stakeholder feedback on the scope and work product developed thus far. The drafting team will use the informal feedback to finalize the preliminary draft of PRC-012-2. Stakeholders may communicate additional feedback directly to the drafting team through its open meetings leading up to the first formal posting. The next meeting is scheduled for June 8-11, 2015. Meeting details will be posted to the NERC calendar early May 2015.

Documents and information about this project are available on the project page. If you have questions, contact Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

Background Information

This project is addressing all aspects of Remedial Action Schemes (RAS) and Special Protection Systems (SPS) contained in the RAS/SPS-related Reliability Standards: PRC-012-1, PRC-013-1, PRC-014-1, PRC-015-1, and PRC-016-1. The maintenance of the Protection System components associated with RAS (PRC-017-1 Remedial Action Scheme Maintenance and Testing) are already addressed in PRC-005-2. PRC-012-2 addresses the testing of the non-Protection System components associated with RAS/SPS.

In FERC Order No. 693 (dated March 16, 2007), the Commission identified PRC-012-0, PRC-013-0, and PRC-014-0 as “fill-in-the-blank” standards and did not approve or remand them because they are applicable to the Regional Reliability Organizations (RROs), assigning the RROs the responsibility to establish regional procedures and databases, and to assess and document the operation, coordination, and compliance of RAS/SPS. The deference to regional practices precludes the consistent application of RAS/SPS-related Reliability Standard requirements.

The proposed draft of PRC-012-2 corrects the applicability of the fill-in-the-blank standards by assigning the requirement responsibilities to the specific users, owners, and operators of the Bulk-Power System; and incorporates the reliability objectives of all the RAS/SPS-related standards.

Questions

Requirements R1, R2, and R3 pertain to the submittal of Attachment 1 information to the Reliability Coordinator (RC) for the review of RAS, the RC using Attachment 2 as a guide for performing the RAS review, and the RC approving the RAS prior to the RAS being placed in-service. Questions 1-4 are relevant for these activities.

1. **RAS review and approval:** Do you agree that RAS should be reviewed and approved by an independent party prior to placing the RAS in-service? If no, please state the basis for your disagreement and an alternative approach.

   ☐ Yes
   ☐ No
   Comments:

2. **Information listed in Attachment 1:** Do you agree that the RAS information required in Attachment 1 is a comprehensive list? If no, please identify what other information you think is necessary for a thorough RAS review.

   ☐ Yes
   ☐ No
   Comments:

3. **Choice of Reliability Coordinator (RC):** Do you agree with the RC being the functional entity designated to review the RAS? If no, please provide the basis for your disagreement, your choice of functional entity to conduct the reviews, and the rationale for your choice.

   ☐ Yes
   ☐ No
   Comments:

4. **Checklist in Attachment 2:** Do you agree that the checklist in Attachment 2 provides a comprehensive guide for the RC to facilitate a thorough RAS review? If no, please identify what other reliability-related considerations should be included in Attachment 2 and the rationale for your choice.

   ☐ Yes
   ☐ No
   Comments:

Requirement R4 mandates the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, as well as the BES performance following an inadvertent operation of the RAS.

The drafting team considered the RAS classification systems used by several Regions to be rooted in PRC-012, Requirement R1, R1.4. which reads: *"Requirements to demonstrate 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."* Although, the drafting team is not proposing to use formal RAS classifications, the intent of PRC-012, Requirement R1, R1.4. is retained in Requirement 4 and Attachment 1.

Questions 5 and 6 pertain to these topics.

5. **Choice of Transmission Planner (TP):** Do you agree with the TP being the functional entity designated to evaluate the RAS? If no, please provide the basis for your disagreement, your choice of functional entity to conduct the evaluations, and the rationale for your choice.

   ☐ Yes
   ☐ No
   Comments:

6. **No RAS Classification:** Do you agree that the language of Requirement R4, its Parts, and Attachment 1 accomplish the objectives of RAS "classification" without having a formal RAS classification system in the standard? If no, please provide the basis for your disagreement and describe an alternate proposal.

   ☐ Yes
   ☐ No
   Comments:

Requirement R6 mandates each RAS-owner analyze each RAS operation or failure of a RAS to operate to identify performance deficiencies. Question 7 pertains to Requirement R6.

7. **RAS Operational Analyses:** Do you agree that the application of Requirement R6 and its Parts would identify performance deficiencies in RAS? If no, please provide the basis for your disagreement and an alternate proposal.

   ☐ Yes
   ☐ No
   Comments:

Requirements R5 and R7 pertain to the submittal of Corrective Action Plans (CAPs) to the Reliability Coordinator (RC) for review, and Requirement R8 mandates the implementation of each CAP. Question 8 addresses these requirements.

8. **Corrective Action Plans:** Do you agree that the application of Requirements R5, R7, and R8 would address the reliability objectives associated with CAPs? If no, please provide the basis for your disagreement and describe an alternate proposal.

☐ Yes
☐ No
Comments:

Requirement R9 mandates each RAS-owner periodically perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. Question 9 pertains to Requirement R9.

9. **Functional Testing of RAS:** Do you agree that functional testing of each RAS would verify the overall RAS performance and the proper operation of non-Protection System components? If no, please provide the basis for your disagreement and describe an alternate proposal.

☐ Yes
☐ No
Comments:

Requirements R10 and R11 pertain to the RAS database, Attachment 3, and the sharing of RAS information for reliability-related needs. Questions 10 11, 12, and 13 pertain to these topics.

10. **Choice of Reliability Coordinator (RC):** Do you agree with the RC being the functional entity designated to maintain the RAS database in Requirement R10? If no, please provide the basis for your disagreement, your choice of functional entity, and the rationale for your choice.

☐ Yes
☐ No
Comments:

11. **Information listed in Attachment 3:** Do you agree that the RAS information required in Attachment 3 (Requirement R10) provides the RC with enough detail of each RAS to meet its reliability-related needs? If no, please identify what other reliability-related information should be included in Attachment 3 and the rationale for your choice.

☐ Yes
☐ No
Comments:

12. **Requirement R11:** Do you agree that there a reliability benefit to Requirement R11? Please provide the rationale for your answer.

☐ Yes
☐ No
Comments:

13. **Choice of RAS-entity:** Do you agree with the RAS-entity being the entity designated to provide the detailed RAS information to other registered entities with a reliability-related need in Requirement R11? If no, please provide the basis for your disagreement, your choice of entity, and the rationale for your choice.

☐ Yes
☐ No
Comments:

14. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

Comments:

NERC

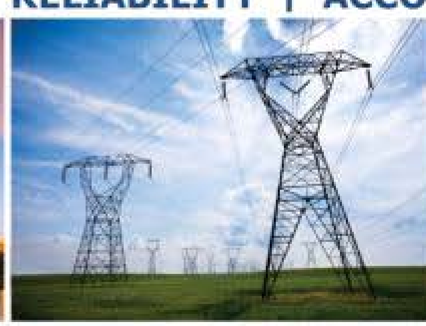
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Special Protection Systems (SPS) and Remedial Action Schemes (RAS):

Assessment of Definition, Regional Practices, and Application of Related Standards

Revision 0.1 – April 2013

RELIABILITY | ACCOUNTABILITY

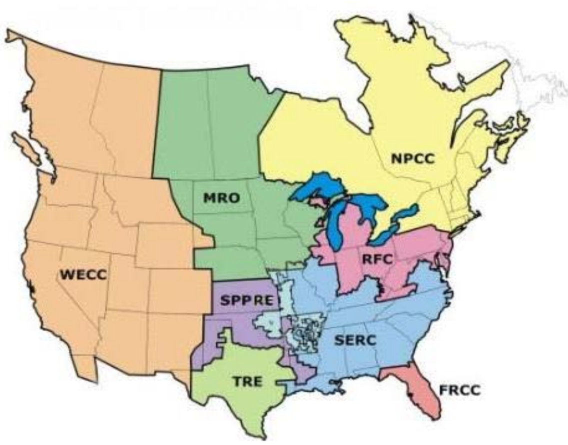


3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to enhance the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a ten-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight Regional areas, as shown on the map and table below. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.



Note: The highlighted area between SPP RE and SERC denotes overlapping Regional area boundaries. For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.

NERC Regional Entities	
FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corporation
MRO Midwest Reliability Organization	**SPP RE** Southwest Power Pool Regional Entity
NPCC Northeast Power Coordinating Council	**TRE** Texas Reliability Entity
RFC ReliabilityFirst Corporation	**WECC** Western Electricity Coordinating Council

[1] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. NERC's reliability standards are also mandatory in Nova Scotia and British Columbia. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

Table of Contents

This technical document was approved by the NERC Planning Committee on March 5, 2013.

Executive Summary

The existing NERC Glossary of Terms definition for a Special Protection System (SPS or, as used in the Western Interconnection, a Remedial Action Scheme or RAS) lacks clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions, leading to inconsistent application of the related NERC Reliability Standards. In addition, three of the related standards (PRC-012-0, PRC-013-0, and PRC-014-0) were identified by FERC in Order No. 693 as fill-in-the-blank standards and consequently are not mandatory and enforceable.

NERC Standards Project 2010-05.2, Phase 2 of Protection Systems: SPS and RAS, will modify the current standards and definitions related to SPS and RAS. The NERC Standards Committee has identified that prior to initiating a project to address these issues, additional research is necessary to clearly define the problem and recommend solutions for consideration. A request for research was submitted by the Standards Committee on January 9, 2012 (see Appendix D). The Planning Committee had already approved a joint effort by the System Analysis and Modeling Subcommittee (SAMS) and System Protection and Control Subcommittee (SPCS) [2] on June 8, 2011 (see Appendix E) which includes issues identified in the request for research. This report addresses all issues identified in the scope of the joint SAMS and SPCS project as well as the Standards Committee request for research; upon approval by the Planning Committee the report should be forwarded to the Standards Committee to support Project 2010-05.2.

This report includes recommendations for a new definition of SPS and revisions to the six SPS-related PRC standards. A strawman definition is provided that eliminates ambiguity in the existing definition and identifies 13 types of schemes that are not SPS, but for which uncertainty has existed in the past based on experience within the Regions. The report also recommends that SPS should be classified based on the type of event to which the SPS responds and the consequence of misoperation. Classification of SPS facilitates standard requirements commensurate with potential reliability risk. Four classifications are proposed.

This report provides recommendations to address FERC concerns with PRC-012-0, PRC-013-0, and PRC-014-0, which assign requirements to Regional Reliability Organizations. Recommendations are made to reassign requirements to specific users, owners, and operators of the bulk power system to remedy this situation.

Project 2010-05.2 should consolidate the requirements pertaining to review, assessment, and documentation of SPS into one standard that includes continent-wide procedures for reviewing new or modified SPS, for assessing existing SPS in annual transmission planning assessments, and for periodic comprehensive SPS assessments. The project also should revise requirements pertaining to analysis and reporting of SPS misoperations in a revision of standard PRC-016-0.1. Due to the significant difference between protection systems and SPS, the subject of SPS misoperations should not be included in a future revision of PRC-004. Given the scope of work and need for drafting team members with different subject matter expertise it may be appropriate to sub-divide Project 2010-05.2 to address review, assessment and documentation of SPS separately from analysis and reporting of misoperations. This report also provides recommendations for Standards Committee consideration that are outside the scope of Project 2010-05.2. These additional recommendations pertain to maintenance and testing and operational aspects of SPS.

[2] The original scope of work involved the SPCS and the predecessor of SAMS, the Transmission Issues Subcommittee (TIS).

Introduction

Problem Statement

The existing NERC Glossary of Terms definition for a Special Protection System (SPS or, as used in the Western Interconnection, a Remedial Action Scheme or RAS) lacks clarity and specificity necessary for consistent identification and classification of protection schemes as SPS or RAS across the eight NERC Regions, leading to inconsistent application of the related NERC Reliability Standards. In addition, three of the related standards (PRC-012-0, PRC-013-0, and PRC-014-0) were identified by FERC in Order No. 693 as fill-in-the-blank standards and consequently are not mandatory and enforceable.

NERC Standards Project 2010-05.2, Phase 2 of Protection Systems: SPS and RAS, will modify the current standards and definitions related to SPS and RAS. The NERC Standards Committee has identified that prior to initiating a project to address these issues, additional research is necessary to clearly define the problem and recommend solutions for consideration.

Background

NERC Definitions

The existing NERC *Glossary of Terms* defines an SPS and RAS as:

> *Special Protection System (Remedial Action Scheme)*
>
> An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

In this document, use of the term SPS in general discussions and proposals for future definitions and standards apply to both SPS and RAS. Specific references to existing practices within Regions use the term SPS or RAS as appropriate for that Region.

The NERC *Glossary of Terms* defines a Protection System as:

> *Protection System*
>
> - Protective relays which respond to electrical quantities,
> - Communications systems necessary for correct operation of protective functions
> - Voltage and current sensing devices providing inputs to protective relays,
> - Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
> - Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Inclusion of the words "protection system" in the term Special Protection System has raised questions whether this is an intentional reference such that SPS are a subset of Protection Systems. Use of protection system (lower case) within the SPS definition identifies that SPS are not Protection Systems. While SPS may include the same types of components as Protection Systems, SPS are not limited to detecting faults or abnormal conditions and tripping affected equipment. SPS may, for example, effect a change to the operating state of power system elements to preserve system stability or to avoid unacceptable voltages or overloads in response to system events. There are many reasons for implementing an SPS; for example, an SPS can be implemented to ensure compliance with the TPL Reliability Standards, to mitigate temporary operating conditions or abnormal configurations (e.g., during construction or maintenance activities), or in instances where system operators would not be able to respond quickly enough to avoid adverse system conditions.

A second area in which the existing SPS definition lacks clarity is the actions that are characteristics of SPS. The actions listed in the definition are broad and may unintentionally include equipment whose purpose is not expressly related to preserving system reliability in response to an event. Inclusion of any system taking “corrective action other than … isolation of faulted components to maintain system reliability” could be deemed to include equipment such as voltage regulators and switching controls for shunt reactive devices. This inclusion would then make these elements subject to single component failure considerations (sometimes referred to as redundancy considerations), coordination, reporting, and maintenance and testing requirements that may be required in the NERC Reliability Standards related to SPS.

This report proposes a revised definition of SPS to address these issues. Development of the proposed definition considered other definitions, common applications, and existing practices regarding classification of SPS.

NERC Reliability Standards

The NERC Reliability Standards contain six standards in the protection and control (PRC) series that specifically pertain to SPS.

- PRC-012-0: Special Protection System Review Procedure
- PRC-013-0: Special Protection System Database
- PRC-014-0: Special Protection System Assessment
- PRC-015-0: Special Protection System Data and Documentation
- PRC-016-0.1: Special Protection System Misoperations
- PRC-017-0: Special Protection System Maintenance and Testing

Three of these standards are not mandatory and enforceable because FERC identified them as fill-in-the-blank standards in Order No. 693, *Mandatory Reliability Standards for the Bulk-Power System*. These standards assign the Regional Reliability Organizations responsibility to establish regional procedures and databases, and to assess and document the operation, coordination, and compliance of SPS. The deference to regional practices, coupled with lack of clarity in the definition of SPS, preclude consistent application of requirements pertaining to SPS. This report provides recommendations that may be implemented through the NERC Reliability Standards Development Process to consolidate the standards and provide greater consistency and clarity regarding requirements.

Chapter 1 – SPS Definition

Considerations for a Revised Definition

Other Definitions in Industry
Several IEEE papers[3] define a similar term to SPS: System Integrity Protection System (SIPS). Adopting the SIPS definition is not appropriate because it is more inclusive than NERC's definition:

> "The SIPS encompasses special protection system (SPS), remedial action schemes (RAS), as well as other system integrity schemes, such as underfrequency (UF), undervoltage (UV), out-of-step (OOS), etc."[4]

NERC applies special consideration to UF and UV load shedding schemes in the Reliability Standards and considers OOS relaying in the context of traditional protection systems. Thus, SIPS is not an appropriate term for use in the Reliability Standards, and a new definition of SPS is more appropriate.

Common Application of SPS in Industry
Most SPS are used to address a range of system issues including stability, voltage, and loading concerns. Less common applications include arresting sub-synchronous resonance and suppressing torsional oscillations. Actions taken by SPS may include (but are not limited to): system reconfiguration, generation rejection or runback, load rejection or shedding, reactive power or braking resistor insertion, and runback or fast ramping of HVdc.

SPS are often deployed because the operational solutions they facilitate are substantially quicker and less expensive to implement than construction of transmission infrastructure. Permanent SPS have been implemented in some cases where the cost associated with system expansion is prohibitive, construction is not possible due to physical constraints, or obtaining permits is not feasible. In other cases temporary SPS have been implemented to maintain system reliability until transmission infrastructure is constructed; or when a reliability risk is temporary (e.g., during equipment outages) and the expense associated with permanent transmission upgrades is not justified.

The deployment of SPS adds complexity to power system operation and planning:

> "Although SPS deployment usually represents a less costly alternative than building new infrastructure, it carries with it unique operational elements among which are: (1) risks of failure on demand and of inadvertent activation; (2) risk of interacting with other SPS in unintended ways; (3) increased management, maintenance, coordination requirements, and analysis complexity."[5]

Subsequent sections of this report consider these three operational elements and provide recommendations regarding how they should be addressed in the NERC Reliability Standards. A summary of the number of schemes identified as SPS or RAS by Region is provided below.

Table 1: Overview of SPS by Region[6]

Region	Total Number	Region	Total Number
FRCC	20	SERC	20
MRO	36	SPP	6
NPCC	117	TRE	24
RFC	47	WECC	192

[3] One noteable reference, Madani, et al, "IEEE PSRC Report on Global Industry Experiences with System Integrity Protection Schemes (SIPS)," IEEE Trans. on Power Delivery, Vol. 25, Oct. 2010.
[4] *Ibid*.
[5] McCalley, et al, "System Protection Schemes: Limitations, Risks, and Management", PSERC Publication 10-19, Dec 2010.
[6] Numbers for 2011 obtained from data reported in the NERC Reliability Metric ALR6-1.

Classification of SPS Types

Three regions classify SPS according to various criteria, including the type of event the SPS is designed to address as well as the ability of the SPS to impact on a local versus wide-area reliability. The following information describes how NPCC, WECC and TRE classify SPS. Please note that examples of regional practices are provided for illustration throughout this document, but are not necessarily best practices or applicable to all Regions. Also in this context, what constitutes local versus wide-area varies among Regions and is not based on the NERC glossary term Wide Area, which is specific to calculation of Interconnection Reliability Operating Limits (IROL).[7]

NPCC

Type I – A Special Protection System which recognizes or anticipates abnormal system conditions resulting from design and operating criteria contingencies, and whose misoperation or failure to operate would have a significant adverse impact outside of the local area. The corrective action taken by the Special Protection System along with the actions taken by other protection systems are intended to return power system parameters to a stable and recoverable state.

Type II – A Special Protection System which recognizes or anticipates abnormal system conditions resulting from extreme contingencies or other extreme causes, and whose misoperation or failure to operate would have a significant adverse impact outside of the local area.

Type III – A Special Protection System whose misoperation or failure to operate results in no significant adverse impact outside the local area.

The following terms are also defined by NPCC to assess the impact of the SPS for their classification:

Significant adverse impact – With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from faults or disturbances, shall be deemed as having significant adverse impact:

a. system instability;
b. unacceptable system dynamic response or equipment tripping;
c. voltage levels in violation of applicable emergency limits;
d. loadings on transmission facilities in violation of applicable emergency limits;
e. unacceptable loss of load.

Local area – An electrically confined or radial portion of the system. The geographic size and number of system elements contained will vary based on system characteristics. A local area may be relatively large geographically with relatively few buses in a sparse system, or be relatively small geographically with a relatively large number of buses in a densely networked system.

WECC

Local Area Protection Scheme (LAPS): A Remedial Action Scheme (RAS) whose failure to operate would NOT result in any of the following:

- Violations of TPL-(001 thru 004)-WECC-1-CR – System Performance Criteria,
- Maximum load loss ≥ 300 MW,
- Maximum generation loss ≥ 1000 MW.

[7] The NERC Glossary defines Wide Area as "The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits."

Wide Area Protection Scheme (WAPS): A Remedial Action Scheme (RAS) whose failure to operate WOULD result in any of the following:

- Violations of TPL-(001 thru 004)-WECC-1-CR – System Performance Criteria,
- Maximum load loss ≥ 300 MW,
- Maximum generation loss ≥ 1000 MW.

Safety Net: A type of Remedial Action Scheme designed to remediate TPL-004-0 (System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)), or other extreme events.

TRE:

(a) A "Type 1 SPS" is any SPS that has wide-area impact and specifically includes any SPS that:

(i) Is designed to alter generation output or otherwise constrain generation or imports over DC Ties; or

(ii) Is designed to open 345 kV transmission lines or other lines that interconnect Transmission Service Providers (TSPs) and impact transfer limits.

(b) A "Type 2 SPS" is any SPS that has only local-area impact and involves only the facilities of the owner-TSP.

These three regional classifications can be roughly mapped:

- NPCC Type I = WECC WAPS = TRE Type 1
- NPCC Type III = WECC LAPS = TRE Type 2
- NPCC Type II = WECC Safety Net

SPS classification differentiates the reliability risk associated with SPS and provides a means to establish more or less stringent requirements consistent with the reliability risk. For example, it may be appropriate to establish less stringent requirements pertaining to monitoring or single component failure of SPS that present a lower reliability risk. A recommendation for classification of SPS is included with the proposed definition and subsequent discussion of standard requirements includes recommendations where different requirements based on classification are deemed appropriate.

Common Exclusions from the SPS Definition in Industry

Exclusions provide a means to assure that specific protection or control systems are not unintentionally included as SPS. The NERC glossary definition of SPS states that "An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS)."

Even with the exclusions in the NERC definition, other commonly applied protection and control systems meet the general language in the SPS definition. Considerable effort has been expended by industry discussing what systems are SPS. NPCC and SERC have documented examples of exclusions to the SPS definition in their regional guidelines. NPCC explicitly excludes "Automatic underfrequency load shedding; Automatic undervoltage load shedding and manual or automatic locally controlled shunt devices."[8] SERC's SPS guideline calls out specific exclusions as follows:

a. UFLS and/or UVLS,

b. Fault conditions that must be isolated including bus breakup / backup / breaker failure protection,

c. Relays that protect for specific equipment damage (such as overload, overcurrent, hotspot, reclose blocking, etc.),

d. Out of step relaying,

e. Capacitor bank / reactor controls,

[8] NPCC *Glossary of Terms Used by Directories*

f. Load Tap Changer (LTC) controls,

g. Automated actions that could be performed by an operator in a reasonable amount of time, including alternate source schemes, and

h. Scheme that trips generation to prevent islanding

A recommended list of protection and control systems that should be excluded from classification as SPS is included with the proposed definition.

Exclusion for Operator Aides

SAMS and SPCS considered a number of factors in discussing this subject including:

1) whether the actions are required to be completed with such urgency that it would be difficult for an operator to react and execute in the necessary time, and

2) whether the required actions are of such complexity or across such a large area that it would be difficult for an operator to perform the actions in the necessary time.

It is difficult to address these questions with concise and measurable terms, making it difficult to explicitly exclude them in the definition without introducing ambiguous terms counter to the objective of providing needed clarity in the SPS definition. Whether its existence is based upon convenience or not, any automated system with the potential to impact bulk power system reliability should be defined and expressed to the appropriate authority (e.g., Planning Coordinator, Reliability Coordinator) for the purposes of system modeling and coordination studies, to ensure that these systems are properly coordinated with other protection and control systems, and to ensure that inadvertent operations do not result in adverse system impacts.

On these bases, SAMS and SPCS decided not to provide an exclusion for schemes based on a general criterion as to whether the scheme automates actions that an operator could perform in a reasonable amount of time or schemes installed for operator convenience. However, SAMS and SPCS do recommend exclusions for specific applications that meet these criteria such as automatic sequences that are initiated manually by an operator. Furthermore, any scheme that is not installed "to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of two or more elements removed, an extreme event, or Cascading" would be excluded by definition, regardless of whether it is installed to assist an operator.

Voltage Threshold

All elements, at any voltage level, of an SPS intended to remediate performance issues on the bulk electric system (BES), or of an SPS that acts upon BES elements, should be subject to the NERC requirements.

Proposed Definition

The proposed definition clarifies the areas that have been interpreted differently between individual entities and within Regions, in some cases leading to differing regional definitions of SPS. The proposed definition provides a framework for differentiating among SPS with differing levels of reliability risk and will support the drafting of new or revised SPS standards.

Special Protection System (SPS)

A scheme designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of faulted elements, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading.

Subject to the exclusions below, such schemes are designed to maintain system stability, acceptable system voltages, acceptable power flows, or to address other reliability concerns. They may execute actions that include but are not limited to: changes in MW and Mvar output, tripping of generators and other sources, load curtailment or tripping, or system reconfiguration.

The following schemes do not constitute an SPS in and of themselves:

a) Underfrequency or undervoltage load shedding

b) Locally sensing devices applied on an element to protect it against equipment damage for non-fault conditions by tripping or modifying the operation of that element, such as, but not limited to, generator loss-of-field or transformer top-oil temperature

c) Autoreclosing schemes

d) Locally sensed and locally operated series and shunt reactive devices, FACTS devices, phase-shifting transformers, variable frequency transformers, generation excitation systems, and tap-changing transformers

e) Schemes that prevent high line voltage by automatically switching the affected line

f) Schemes that automatically de-energize a line for non-fault operation when one end of the line is open

g) Out-of-step relaying

h) Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)

i) Protection schemes that operate local breakers other than those on the faulted circuit to facilitate fault clearing, such as, but not limited to, opening a circuit breaker to remove infeed so protection at a remote terminal can detect a fault or to reduce fault duty

j) Automatic sequences that proceed when manually initiated solely by an operator

k) Sub-synchronous resonance (SSR) protection schemes

l) Modulation of HVdc or SVC via supplementary controls such as angle damping or frequency damping applied to damp local or inter-area oscillations

m) A Protection System that includes multiple elements within its zone of protection, or that isolates more than the faulted element because an interrupting device is not provided between the faulted element and one or more other elements

SPS are categorized into four distinct types. These types may be subject to different requirements within the NERC Reliability Standards.

- Type PS (planning-significant): A scheme designed to meet system performance requirements identified in the NERC Reliability Standards, where failure or inadvertent operation of the scheme can have a significant impact on the BES.
- Type PL (planning-limited): A scheme designed to meet system performance requirements identified in the NERC Reliability Standards, where failure or inadvertent operation of the scheme can have only a limited impact on the BES.
- Type ES (extreme-significant): A scheme designed to limit the impact of two or more elements removed, an extreme event, or Cascading, where failure or inadvertent operation of the scheme can have a significant impact on the BES.
- Type EL (extreme-limited): A scheme designed to limit the impact of two or more elements removed, an extreme event, or Cascading, where failure or inadvertent operation of the scheme can have only a limited impact on the BES.

An SPS is classified as having a significant impact on the BES if failure or inadvertent operation of the scheme results in any of the following:

- Non-Consequential Load Loss ≥ 300 MW

- Aggregate resource loss (tripping or runback of generation or HVdc) > the largest Real Power resource within the interconnection[9]
- Loss of synchronism between two or more portions of the system each including more than one generating plant
- Negatively damped oscillations

If none of these criteria are met, the SPS is classified as having a limited impact on the BES.

Definition of Significant and Limited Impact

The parameters used to define the bright line between "significant" and "limited" impacts are proposed to consider only the electrical scale of the event. Defining the bright line in this way eliminates the difficulty in distinguishing the geographic impact of an SPS as either "wide" or "local."

NERC Standard EOP-004-1, DOE Form OE-417 Electric Emergency Incident and Disturbance Report, establishes the criteria by which an event is categorized as a Disturbance and requires a disturbance report. In terms of SPS, the proposed criteria for significant impact mirrors EOP-004-1 by including a non-consequential load loss value of 300 MW.

NERC Reliability Standards require consideration of loss of any generating unit; therefore, generating unit loss would not impact reliability of the bulk power system unless the combined capacity loss exceeds the largest unit within the interconnection. The generation loss level was selected as a loss greater than the largest unit within an interconnection on this basis.

Tripping multiple generating units exceeding the capacity of the largest unit within an interconnection, system separation (loss of synchronism) that results in isolation of a portion of an interconnection, or system oscillations that increase in magnitude (negatively-damped) are indicators of adverse impact to the reliability of an interconnection. These criteria identify system performance indicative of the potential for instability, uncontrolled separation, or cascading outages, without requiring detailed analyses to confirm the extent to which instability, uncontrolled separation, or cascading outages may occur. These indicators, combined with the loss of load criterion, are proposed to identify the potential reliability risk associated with failure of a SPS. Subsequent sections of this report recommend requirements for assessment and design of SPS based on whether the potential reliability risk associated with the SPS are significant versus limited impacts.

The proposed thresholds differentiate between significant and limited impact. While it should be clear there is no upper threshold on what constitutes a significant impact, there also is no lower threshold proposed as to what constitutes limited impact. Whether a scheme is an SPS is determined by the definition; significant and limited impact are used only to classify SPS. For example, if a scheme is installed to meet system performance requirements identified in the NERC Reliability Standards then it is an SPS regardless of its potential impact. A failure of the SPS would result in a violation of a NERC Reliability Standard. Thus, excluding a scheme with impact below a certain threshold would undermine the reliability objective of the standard requirement the scheme is installed to address.

[9] I.e., Eastern, Western, ERCOT, or Quebec Interconnection.

Chapter 2 – Design and Maintenance Requirements

Under the proposed definition, SPS are implemented to preserve acceptable system performance, and as such may be critical to power system reliability and therefore subject to single component failure considerations, and maintenance and testing requirements outlined in the PRC standards.

General Design Considerations

Aside from the single component failure, and maintenance and testing considerations outlined below, Disturbance Monitoring Equipment should be provided in the design of an SPS to permit analysis of the SPS performance following an event. Also, as with other automated systems, the design of an SPS should facilitate its maintenance and testing.

SPS Single Component Failure Requirements

Requirement R1.3 in PRC-012-0 requires SPS owners to demonstrate an SPS is designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in NERC Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0. This requirement should be retained in future standards such that Types PS and PL SPS are required to be designed so that power system performance meets the performance requirements of TPL-001-0, TPL-002-0, or TPL-003-0, in the event of a single component failure. The design of Type PS and PL SPS can provide the required performance through any of the methods outlined below, or a combination of these methods:

1. Arming more load or generation than necessary to meet the intended results. Thus the failure of the scheme to drop a portion of load or generation would not be an issue. In this context it is necessary to arm the tripping of more load delivery points or generating units rather than simply arming more MW of load or generation. When this option is used, studies of the SPS design must demonstrate that tripping the total armed amount of load or generation will not cause other adverse impacts to reliability.

2. Providing redundancy of SPS components listed below.

   - Any single ac current source and/or related input to the SPS. Separate secondary windings of a free-standing current transformer (CT) or multiple CTs on a common bushing should be considered an acceptable level of redundancy.
   - Any single ac voltage source and/or related input to the SPS. Separate secondary windings of a common capacitance coupled voltage transformer (CCVT), voltage transformer (VT), or similar device should be considered an acceptable level of redundancy.
   - Any single device used to measure electrical quantities used by the SPS.
   - Any single communication channel and/or any single piece of related communication equipment used by the SPS.
   - Any single computer or programmable logic device used to analyze information and provide SPS operational output.
   - Any single element of the dc control circuitry that is used for the SPS, including breaker closing circuits.
   - Any single auxiliary relay or auxiliary device used by the SPS.
   - Any single breaker trip coil for any breaker operated by the SPS.
   - Any single station battery or single charger, or other single dc source, where central monitoring is not provided for both low voltage and battery open conditions.

3. Using remote or time delayed actions such as breaker failure protection[10] or alternative automatic actions to back up failures of single components (e.g., an independent scheme that trips an element if an overload exists for longer than the time necessary for the SPS to take action). The backup operation would still need to provide mitigation to meet the necessary result in the required timeframe.

4. For Type PL SPS, manual backup operation may be used to address the failure of a single SPS component if studies are provided to show that implemented procedures will be effective in providing the required response when a SPS failure occurs. The implemented procedures will include alarm response and manual operation time requirements to provide the backup functions.

Some SPS utilize an Energy Management System (EMS) system for transmitting signals or calculating information necessary for SPS operation such as the amount of load or generation to trip. Loss of the EMS system must be considered when assessing the impact of a single component failure. For example, when the EMS is used to transmit a signal, a separate communication path must be available. When a non-redundant EMS provides a calculated value to two otherwise independent systems, a backup calculation or default value must be provided to the SPS in the event of an EMS failure.

Types ES and EL SPS are designed to provide system protection against extreme events. The events that Types ES and EL SPS are intended to address have a lower probability of occurrence and the TPL standards do not require mitigation for these events. Dependability of SPS operation is therefore not critical for these events and, consistent with the existing standards, these SPS should not be required to perform their protection functions even with a single component failure. Design requirements for Type ES SPS should emphasize security; however, in some cases Type ES SPS are installed to address an event with consequences so significant (e.g., system separation or collapse of an interconnection) that consideration should be given to both dependability and security. In consideration that the addition of redundancy in some cases might make the SPS less secure, such cases may warrant implementation of a voting scheme[11].

Maintenance and Testing

The Project 2007-17, Protection System Maintenance and Testing, drafting team revised PRC-005 to include maintenance and testing requirements for SPS contained in PRC-017-0.[12] All of the existing requirements in PRC-017-0 that are based on a reliability objective are mapped to PRC-005-2. However, this report identifies two subjects that are not covered in either the existing standard or the proposed standard:

- Complex SPS require different procedures than those used for maintenance of protection systems.
- Maintenance of non-protection system components used in SPS is not addressed in any existing NERC Reliability Standards.

These subjects should be addressed in a future revision of PRC-005 or development of a separate standard.

[10] In this context it is not intended that breaker failure protection must be redundant; rather, that breaker failure protection may be relied on to meet the design requirements (e.g., if an SPS required tripping a breaker with a single trip coil).

[11] A voting scheme achieves both dependable and secure operation by requiring, for example, two out of three schemes to detect the condition prior to initiating action.

[12] PRC-005-2 was adopted by the NERC Board of Trustees on November 7, 2012

Chapter 3 – Study and Documentation Requirements

Review and Approval of New or Modified SPS

Requirement R1 in PRC-012-0 requires each Regional Reliability Organization to have a documented review procedure to ensure that SPS comply with regional criteria and NERC Reliability Standards. However, the potential for SPS interaction and for SPS operation or misoperation to have inter-regional impacts suggests that a uniform procedure for reviewing SPS is important to ensure bulk power system reliability. This report recommends fundamental aspects that should be included in a continent-wide SPS review procedure and included in the revised reliability standards pertaining to SPS. The review process should be conducted by an entity or entities with the widest possible view of system reliability, and must be a user, owner, or operator of the bulk power system. To assure that both planning and operating views are evaluated before a new or modified SPS is placed in service, responsibility for reviewing and approving implementation of SPS should be assigned to the Reliability Coordinator and Planning Coordinator. Ideally these reviews should be performed on a regional or interconnection-wide basis. If in the future an entity is registered as the Reliability Assurer for each Region, the responsibility for performing these reviews, or alternately for coordinating these reviews, should be assigned to the Reliability Assurer.

A continent-wide review process should be established in a revised reliability standard that includes the following aspects:

- The SPS owner[13] should be required to obtain approval from its Reliability Coordinator and its Planning Coordinator in whose area the SPS is installed[14] prior to placing a new or modified SPS in service.
- An entity proposing a new or modified SPS should be required to file an application with its Reliability Coordinator and Planning Coordinator that includes the following information:
    - A document outlining the details of the SPS as specified below in the section titled, Data Submittals by Entities that Own SPS.
    - Studies that demonstrate the operation, coordination, and effectiveness of the SPS, including the impacts of correct operation, a failure to operate, and inadvertent operation. The study report should include the following:[15]
        - Entity conducting the SPS study
        - Study completion date
        - Study years
        - System conditions
        - Contingencies analyzed
        - Demonstration that the SPS meets criteria discussed in the Design Considerations chapter of this report
        - Discussion of coordination of the SPS with other SPS, UFLS, UVLS, and protection systems
- The Reliability Coordinator and Planning Coordinator should be required to provide copies of the application and supporting information to Transmission Planners, Transmission Operators, and Balancing Authorities within their area, and to adjacent Reliability Coordinators and Planning Coordinators.
- Entities receiving the application should be allowed to provide comments to the Reliability Coordinator and Planning Coordinator.

[13] In cases where more than one entity owns an SPS, the standards should designate that a designated "reporting entity" be responsible for transmitting data to the Reliability Coordinator and Planning Coordinator, while all owners retain responsibility for other requirements such as maintenance and testing.

[14] In cases where an SPS has components installed in or takes action in more than one Reliability Coordinator area or Planning Coordinator area, all affected Reliability Coordinators and Planning Coordinators should have approval authority.

[15] The same documentation requirements should apply to Periodic Comprehensive Assessments of SPS Coordination.

- When deciding whether to approve an SPS, the Reliability Coordinator and the Planning Coordinator in whose area the SPS is to be installed or modified should be required to consider supporting information provided with the application; comments from Transmission Planners, Transmission Operators, and Balancing Authorities and other Reliability Coordinators and Planning Coordinators; and any supplemental information provided by the SPS owner.
- The basis of the Reliability Coordinator and Planning Coordinator approval should be limited to whether all required information has been submitted and the studies are sufficient to support that all performance requirements are met.

Assessment of Existing SPS

Study of SPS in Annual Transmission Planning Assessments

Requirement R1 in PRC-014-0 specifically addresses assessment of the operation, coordination, and effectiveness of all SPS and assigns this responsibility to the Regional Reliability Organization. Reliability standards must assign responsibility to owners, operators, and users of the bulk power system. For assessments of SPS, it is important to identify an entity with the necessary expertise in system studies and a wide-area view to facilitate coordination of SPS across the system. Instead of assigning this responsibility to the Regional Reliability Organization or the Regional Entity, the assessment responsibility should be assigned to the Planning Coordinator and Transmission Planner for SPS within their specific area.

Annually, the Planning Coordinator and Transmission Planner should review the operation, coordination, and effectiveness of the SPS, including the impacts of correct operation, a failure to operate, and inadvertent operation. If system changes have occurred which can affect the operation of the SPS, annual studies should include system conditions and contingencies modeled in the study supporting the application for installation of or modifications to an SPS.

Any issues identified should be documented and submitted to the Reliability Coordinator and the SPS owner. The Reliability Coordinator and Planning Coordinator should be required to determine, in consultation with the SPS owner, whether a corrective action plan is required, and if so, whether the SPS can remain in-service or must be removed from service until a corrective action plan is implemented. If a corrective action plan is required, the SPS owner should be required to submit an application for a modified SPS as described above in the section titled Review and Approval of New or Modified SPS.

Periodic Comprehensive Assessments of SPS Coordination

Comprehensive assessment should occur every five years, or sooner, if significant changes are made to system topology or operating characteristics that may impact the coordination among SPS and between SPS and UFLS, UVLS, and other protection systems. Responsibility for the comprehensive assessment should be assigned to the Reliability Coordinator to achieve the wide-area review necessary for a comprehensive assessment. Planning Coordinators, Transmission Planners, Transmission Operators, Balancing Authorities, and adjacent Reliability Coordinators should be required to provide support to the Reliability Coordinator when requested to do so. As part of the periodic review the Reliability Coordinator should be required to request the Planning Coordinator and Transmission Planner to assess and document whether the SPS is still necessary, serves its intended purpose, meets criteria discussed in the Design Considerations chapter of this report, coordinates with other SPS, UFLS, UVLS, and protection systems, and does not have unintended adverse consequences on reliability.

The Reliability Coordinator should be required to provide its periodic assessment to Planning Coordinators, Transmission Planners, Transmission Operators, and Balancing Authorities in its area, and to adjacent Reliability Coordinators, and should be required to consider comments provided by these entities. Any issues identified with an SPS should be documented and submitted to the SPS owner. If any concerns are identified, the Reliability Coordinator and the Planning Coordinator in whose area the SPS is installed should determine, in consultation with the SPS owner, whether a corrective action plan is required, and if so, whether the SPS can remain in-service or must be removed from service until a corrective action plan is implemented. If a corrective action plan is required, the SPS owner should be required to submit an application for a modified SPS as described above in the section titled Review and Approval of New or Modified SPS.

Documentation Requirements

Data Submittals by Entities that Own SPS

Reliability standard PRC-015-0 establishes requirements for SPS owners to provide data for existing and proposed SPS as specified in reliability standard PRC-013-0 Requirement R1. PRC-013-0 establishes the data provided shall include the following:

- Design Objectives — Contingencies and system conditions for which the SPS was designed
- Operation — The actions taken by the SPS in response to Disturbance conditions
- Modeling — Information on detection logic or relay settings that control operation of the SPS

This requirement should be carried forward to the revised standards for the SPS owner to provide detailed information regarding the conditions of SPS operation. However, this requirement should be modified to ensure that communication of this information is clear and understandable to all entities that require the information to plan and operate the bulk power system (e.g., Planning Coordinators, Transmission Planners, Reliability Coordinators, Transmission Operators, and Balancing Authorities). Additional specificity should be added to this list of data to assure that sufficient information is provided for entities to understand and model SPS operation.

Since SPS design and complexity vary considerably, a brief description of the action taken when certain system conditions are detected generally does not provide a sufficient level of detail. Conversely, logic and control wiring diagrams may provide too much detail that is not readily understood except by the SPS owner’s protection and control engineers. To achieve an appropriate level of detail that provides a common understanding by the SPS owner and other entities, the SPS owner should work with the Transmission Planner to develop a document outlining the details of the SPS operation specifically tailored to the needs and knowledge level of the entities that require this information to plan and operate the bulk power system. The document should include the following:

- SPS name
- SPS owner
- Expected in-service date
- Whether the SPS is intended to be permanent or temporary
- SPS classification (per revised definition), and documentation or explanation of how the SPS mitigates the planning or extreme event and why the impact is significant or limited
- Logic diagram, flow chart, or truth table documenting the scheme logic and illustrating how functional operation is accomplished
- Whether the SPS logic is:
    - Event-based [16]
    - Parameter-based [17]
    - A combination of event-based and parameter-based
- System performance criteria violation necessitating the SPS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery)

[16] Event-based schemes directly detect outages and/or fault events and initiate actions such as generator/load tripping to fully or partially mitigate the event impact. This open-loop type of control is commonly used for preventing system instabilities when necessary remedial actions need to be applied as quickly as possible.

[17] Parameter-based schemes measure variables for which a significant change confirms the occurrence of a critical event. This is also a form of open-loop control but with indirect event detection. The indirect method is mainly used to detect remote switching of breakers (e.g., at the opposite end of a line) and significant sudden changes which can cause instabilities, but may not be readily detected directly. To provide timely remedial action execution, the measured variables may include power, angles, etc., and/or their derivatives.

- Parameters and equipment status monitored as inputs to the SPS (e.g., voltage, current or power flow, breaker position) and specific monitoring points and locations
- Under what conditions the SPS is armed (e.g., always armed, armed for certain system conditions, actuation thresholds)
- Whether arming is accomplished automatically or manually, if required
- Arming criteria – analog quantities and/or equipment status monitored to determine existence of the system condition for which SPS is armed (e.g., generation/load patterns, reactive power reserves, facility loading)
- Action taken – for example: transmission facilities switched in or out; generators tripped, runback, or started; load dropped; tap setting changed (phase-shifting transformer); controller set-point changed (AVR, SVC, HVdc converter); turbine fast valving or generator excitation forcing; braking resistor insertion
- Time to operate, including intentional time delays (e.g., timer settings) and inherent delays (e.g., relay operating time)
- Information with sufficient detail necessary to model the SPS.

SPS Database

PRC-013-0, Requirement R1 requires the Regional Reliability Organization to maintain an SPS database, including data on design objectives, operation, and modeling of each SPS. Similar to the other requirements presently assigned to the Regional Reliability Organization, this requirement should be assigned to a user, owner, or operator of the bulk power system. To minimize the number of databases and facilitate sharing of information with entities that require SPS data to plan and operate the bulk power system, this requirement should be assigned to the Planning Coordinator. The Planning Coordinator should be required to provide its database to NERC for the purpose maintaining a continent-wide data base[18] that NERC would make available to Reliability Coordinators, Transmission Operators, Balancing Authorities, Planning Coordinators, and Transmission Planners that require this data. The database should contain information for each SPS as described above in the section titled, Data Submittals by Entities that Own SPS.

[18] The requirement in a NERC Reliability Standard would be applicable to the Planning Coordinator; the responsibility for NERC to maintain a continent-wide database should be addressed outside the standard.

Chapter 4 – Operational Requirements

Due to their unique nature, SPS may have special operational considerations, with potentially differing requirements among the proposed types for monitoring, notification of status, and the response time required to address SPS failure. Furthermore, consideration should be given to the documentation of procedures for operator interaction with SPS, and how operators should respond to SPS failures.

One entity should be assigned primary responsibility for monitoring, coordination, and control of an SPS. Depending on the complexity, this responsible party may be a Reliability Coordinator, Balancing Authority, or Transmission Operator. Complex SPS may have multiple owners or affected entities, including different functional entities and the chain of notification and control should be clearly established.

Monitoring of Status

Existing NERC Reliability Standard IRO-005-3.1a, Requirement R1.1 requires Reliability Coordinators to monitor SPS. Similarly PRC-001-1, Requirement R6 requires Balancing Authorities and Transmission Operators to monitor SPS. The SPS standards should establish the level of monitoring capability that must be provided by the SPS owner. Classification of the SPS will dictate its design criteria and may lend itself to different levels of monitoring.

All SPS should be monitored by SCADA/EMS with real-time status communicated to EMS that minimally includes whether the scheme is in-service or out-of-service, and the current operational state of the scheme. For SPS that are armed manually the arming status may be the same as whether the SPS is in-service or out-of-service. For SPS that are armed automatically these two states are independent because an SPS that has been placed in-service may be armed or unarmed based on whether the automatic arming criteria have been met. In cases where the classification of the SPS requires redundancy, the minimal status indications should be provided for each system. The minimum status is sufficient for operational purposes; however, where possible it may be useful to provide additional information regarding partial failures or the status of critical components to allow the SPS owner to more efficiently troubleshoot a reported failure. Whether this capability exists will depend in part on the design and vintage of equipment used in the SPS. While all schemes should be required to provide the minimum level of monitoring, new schemes should be designed with the objective of providing monitoring similar to what is provided for microprocessor-based protection systems.

Similarly, the SCADA/EMS presentation to the operator would need to indicate the criticality of the scheme (e.g., through the use of audible alarms and a high priority in the alarm queue). The operator would be expected to know how to respond depending on the nature of the issue detected, as some partial SPS failures might not result in a complete failure of the scheme.

In cases where SPS cross ownership and operational boundaries, it is important that all entities involved with the SPS are provided with an appropriate level of monitoring.

Notification of Status

Since the owner and operator of an SPS or component are often different organizations, and because SPS may cross entity boundaries, it is important that the SPS status is communicated appropriately between entities. Existing NERC Reliability Standards already require some level of notification of SPS status by Reliability Coordinators, Balancing Authorities and Transmission Operators.[19] Furthermore, SPS owners (e.g., Transmission Owner, Generator Owner) should be responsible for communicating scheme or component issues to the operating organizations (e.g., Transmission Operator, Generator Operator), who should then be responsible for communicating the issues to the involved Reliability Coordinator, Balancing Authority, and other Transmission Operators or Generator Operators that might rely on the SPS (for example, in setting operating limits).

The required timing associated with such notification will depend on the type of scheme; for example, the misoperation of a Type PS or ES scheme would require rapid notification to all interested parties. In general, the more critical a scheme is to the reliability of the system, the then more important its notification and response; however, it is also important that some

[19] See, for example, IRO-005-3.1a Requirement R9 and PRC-001-1, Requirement R6.

level notification be made for all schemes, due to the complex nature of SPS and their interaction with each other, to allow entities to understand the reliability impact of a neighboring entity's SPS failure or misoperation.

Response to Failures

As with many of the other issues, the response time required to address SPS failure is tightly coupled to the potential impact of the SPS as well as the operating conditions at the time of failure. For example, if the SPS is intended to address an event with a significant impact such as an IROL, then any corrective action in response to a misoperation would need to be taken in 30 minutes or less, consistent with the T_V[20] associated with the IROL. On the other hand, depending on the operating conditions, a particular scheme's unavailability may not result in an adverse impact to reliability. Actions taken following an SPS failure should consider whether the failure affects dependability or security of the SPS and the potential impact to reliability.

Generally speaking, the SPS failure modes are known and the necessary corrective actions are documented (e.g., contingency plans) so that the system can be placed in a safe operating state. In any case, a full or partial failure of an SPS requires that the system performance level provided by having the SPS in service is met, or a more conservative and safe operating condition would need to be achieved, in a timeframe appropriate for the nature of the SPS and operating conditions. When one system of a redundant SPS fails, the action taken by the operator may depend on the system conditions the SPS is installed to address and the operating conditions at the time of the failure. For example, an operator may respond to failure of one system by operating to higher equipment ratings when an SPS is installed to address thermal loading violations. However, the operator may not be able to rely on the remaining system of a redundant SPS when the SPS is installed to prevent instability, system separation, or cascading outages, in which case the operator must reduce transfers or take other actions to secure the system.

Operational Documentation

Operational documentation is necessary to provide the operator with enough information to understand all aspects of the scheme and is used to provide knowledge transfer as staff changes occur. Overall documentation requirements are identified in the section on Study and Documentation Requirements; however, the operator does not require all information provided by the SPS owner for the database maintained by the Planning Coordinator. The operational documentation is sometimes called a "description of operations" and provides the operation actions for the following areas:

- General Description – This provides an overview of the purpose of the scheme including the monitoring, set points and actions of the scheme. The operator and other stake holders can use this information to understand the need for the scheme.
- Operation – This will provide the specific information concerning, arming, alarming, and actions taken by this scheme including the monitoring points of the scheme. The operator can use this information to provide triage and plan a course of action concerning restoration of the electric system. This information should provide an understanding of what has operated, why these elements have been impacted, and possible mitigations or restoration activities.
- Failures, Alarms, Targeting – This information will provide the operator and first responders with descriptions of alarms and targets and the actions needed when the scheme is rendered unusable either during maintenance or because of a failure. The instructions will guide the operator on how to respond to component failures that partially impair the scheme or those failures that might disable entire scheme.

Regulatory agencies provide oversight of these schemes and require owners of these schemes to provide descriptions and operational information. NERC PRC-015 requires owners to provide description of schemes and the Study and Documentation Requirements section of this report proposes specific documentation requirements for inclusion in a revised standard. In addition to NERC, some Regional Entities also require SPS owners to provide the Region with additional information concerning the operations of the schemes. Some regional regulatory agencies also require the owners to verify that they have taken certain actions after a misoperation or a failure of these schemes.

[20] Specifically, T_V is discussed in NERC Reliability Standard IRO-009-1, Requirement R2.

Chapter 5 – Analysis of SPS Operations

Operations of SPS provide an opportunity to assess their performance in actual operating power systems, as opposed to assessing the impact through a preconceived set of system studies. Analysis of SPS operations is presently addressed in PRC-012-0 and PRC-016-0.1, which establish requirements for Regional Reliability Organizations and SPS owners respectively. PRC-012-0 requires that each Regional Reliability Organization establish a regional definition of an SPS misoperation (R1.6), as well as requirements for analysis and documentation of corrective action plans for all SPS misoperations (R1.7). PRC-016-0.1 requires that SPS owners analyze their SPS operations and maintain a record of all misoperations in accordance with their regional SPS review procedure (R1) and that SPS owners take corrective actions to avoid future misoperations (R2).

PRC-012-0 is one of the standards identified in FERC Order No. 693 as a fill-in-the-blank standard and this standard therefore is not mandatory and enforceable. SAMS and SPCS have not identified any rationale for having regional definitions of an SPS misoperation or regional processes for analyzing SPS operations. Establishment of a continent-wide definition and review process will facilitate meaningful metrics for assessing the impact of SPS misoperations on bulk power system reliability. Rather than revising PRC-012-0 to assign responsibility for developing regional definitions and review processes to a user, owner, or operator of the bulk power system, this report recommends that one continent-wide definition and review process should be established through the NERC Reliability Standard Development Process, and that criteria be established for SPS owners to follow a continent-wide review process in place of the existing requirements in PRC-016-0.1.

SPS Misoperation Definition

Establishing a definition of an SPS misoperation must account for the many different aspects affecting whether operation of an SPS achieves its desired effect on power system performance. In addition to aspects traditionally considered in assessing protection system misoperations such as failure to operate and unnecessary operation, analysis of an SPS operation also must consider whether the action was properly initiated and whether the initiated action achieved the desired power system performance. This report proposes that a tiered definition be used to assess which aspects of an SPS operation are reportable for metric purposes, which require analysis and reporting to the Reliability Coordinator and Planning Coordinator, and which require a corrective action plan. The following definition is recommended for an SPS misoperation.

SPS Misoperation

A SPS Misoperation includes any operation that exhibits one or more of the following attributes:

a. 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 occur.

b. Unnecessary Operation – Any operation of a SPS that occurs without the occurrence of the intended system trigger condition(s).

c. Unintended System Response – Any unintended adverse system response to the SPS operation.

d. Failure to Mitigate – Any failure of the SPS to mitigate the power system conditions for which it is intended.

The SPS review process should include requirements based on the SPS misoperation definition as follows:

- The SPS owner must provide analysis of all misoperations to its Reliability Coordinator and Planning Coordinator.
- The SPS owner must develop and implement a corrective action plan for all SPS misoperations.
- Reporting for reliability metric purposes should be limited to SPS misoperations that exhibit attributes (a) or (b) of the proposed definition, but should be addressed outside PRC-016-1, in a manner similar to the process under development for reporting protection system misoperations in Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

SPS Operation Review Process

The review process should be included in a revised version of PRC-016 and PRC-012-0 should be retired upon approval of a continent-wide definition and revised PRC-016. The SPS operation review process should require that SPS owners analyze all SPS operations in sufficient detail to determine whether or not the response of the power system to the SPS operation is appropriate to meeting the purpose of the SPS. This requirement should be applied uniformly to all SPS types. The time required to review each SPS operation will vary with the complexity of the SPS.

The analysis of each operation should include:

- The power system conditions which triggered the SPS.
- A determination of whether or not the SPS responded as designed.
- An analysis of the power system response to the SPS operation.
- An analysis of the effectiveness of the SPS in mitigating power system issues it was designed to address. This analysis should identify whether or not those issues existed or were likely to occur at the time of the SPS operation.
- Any unintended or adverse power system response to the SPS operation.

For each SPS operation, the analysis should identify the power system conditions which existed at the time of the SPS operation. These conditions should be analyzed to determine whether or not the SPS operation was appropriate. This part of the analysis is to determine both whether or not the SPS operated as designed, and whether or not the conditions the SPS is intended to mitigate were present at the time of SPS operation.

Some SPS use a proxy to determine the possible existence of a system problem. For example, the opening of a generator outlet may cause an overload remote from the generator. An SPS could monitor the status of the outlet and run back generation to avoid the possible overload, rather than monitoring the loading on the potentially impacted element. The analysis should determine whether the SPS responded to the loss of outlet, and whether the overload actually would have occurred without SPS operation.

The analysis should also examine the response of the system to the SPS operation. This part of the analysis is to determine whether or not the SPS is effective in its intended mitigation, and if it has unforeseen adverse or unnecessary impacts on the power system.

As noted with the proposed definition above, the reporting requirements for each SPS misoperation should vary based on the attributes of the misoperation. The following discussion proposes reporting requirements and provides rationale for the type of SPS misoperation to which each should apply.

1. The SPS owner should be required to provide analysis of the misoperation to its Reliability Coordinator and Planning Coordinator for all SPS misoperations. The report should be provided to the Reliability Coordinator and the Planning Coordinator because such misoperations may require a reevaluation of the SPS under the review process proposed in the Study and Documentation Requirements section. The report should include the corrective action to assist the Reliability Coordinator and Planning Coordinator in confirming whether the SPS requires reevaluation.

2. The SPS owner should be required to develop and implement a corrective action plan for all SPS misoperations. Reporting details of the corrective action plan should be limited to purposes supporting reliability. As noted above, the report to the Reliability Coordinator and Planning Coordinator should include corrective actions. If an SPS must be removed from service or its operation is modified pending implementation of the corrective action plan, the status must be reported to the Reliability Coordinator, Transmission Operator, or Balancing Authority.

3. The SPS owner should be required to report for reliability metric purposes any SPS misoperation that involves a failure to operate or unnecessary operation. These attributes are analogous to protection system misoperations that must be reported and involve a failure of the SPS to operate per its installed design. The mechanism for

requiring reporting for reliability metric purposes should be similar to the process for reporting protection system misoperations under development in Project 2010-05.1: Protection Systems: Phase 1 (Misoperations).

4. The SPS owner should not be required to report or develop corrective action plans for other failures associated with an SPS that are not associated with an SPS operation or failure to operate, such as:

   - 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;
   - Unnecessary Arming – Any automatic arming of a SPS that occurs without the occurrence of the intended arming system condition(s); and
   - Failure to Reset – Any failure of a SPS to automatically reset following a return of normal system conditions, if the system design requires automatic reset.

These types of failures can be corrected by the SPS owner without involving the Reliability Coordinator and the Planning Coordinator, and are analogous to a protection system owner identifying a failed power supply on a relay. If the failure has not resulted in a misoperation then reporting and corrective action plans are not required. It should be noted however, that operational requirements apply and if an SPS must be removed from service the status must be reported to the Reliability Coordinator, Transmission Operator, or Balancing Authority.

Chapter 6 – Recommendations

Definition

The existing SPS definition in the NERC glossary lacks clarity and specificity necessary for consistent identification and classification of SPS. The following strawman definition is proposed.

> *Special Protection System*
>
> A scheme designed to detect predetermined system conditions and automatically take corrective actions, other than the isolation of faulted elements, to meet system performance requirements identified in the NERC Reliability Standards, or to limit the impact of: two or more elements removed, an extreme event, or Cascading.
>
> Subject to the exclusions below, such schemes are designed to maintain system stability, acceptable system voltages, acceptable power flows, or to address other reliability concerns. They may execute actions that include but are not limited to: changes in MW and Mvar output, tripping of generators and other sources, load curtailment or tripping, or system reconfiguration.
>
> The following schemes do not constitute an SPS in and of themselves:
>
> a) Underfrequency or undervoltage load shedding
>
> b) Locally sensing devices applied on an element to protect it against equipment damage for non-fault conditions by tripping or modifying the operation of that element, such as, but not limited to, generator loss-of-field or transformer top-oil temperature
>
> c) Autoreclosing schemes
>
> d) Locally sensed and locally operated series and shunt reactive devices, FACTS devices, phase-shifting transformers, variable frequency transformers, generation excitation systems, and tap-changing transformers
>
> e) Schemes that prevent high line voltage by automatically switching the affected line
>
> f) Schemes that automatically de-energize a line for non-fault operation when one end of the line is open
>
> g) Out-of-step relaying
>
> h) Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)
>
> i) Protection schemes that operate local breakers other than those on the faulted circuit to facilitate fault clearing, such as, but not limited to, opening a circuit breaker to remove infeed so protection at a remote terminal can detect a fault or to reduce fault duty
>
> j) Automatic sequences that proceed when manually initiated solely by an operator
>
> k) Sub-synchronous resonance (SSR) protection schemes
>
> l) Modulation of HVdc or SVC via supplementary controls such as angle damping or frequency damping applied to damp local or inter-area oscillations
>
> m) A Protection System that includes multiple elements within its zone of protection, or that isolates more than the faulted element because an interrupting device is not provided between the faulted element and one or more other elements

Classification

SPS should be classified based on the type of event to which the SPS responds and the consequence of misoperation. Classification of SPS facilitates standard requirements commensurate with potential reliability risk. Four classifications are proposed:

- Type PS: planning – significant,
- Type PL: planning – limited,
- Type ES: extreme – significant, and
- Type EL: extreme – limited.

The planning classification applies to schemes designed to meet system performance requirements identified in the NERC Reliability Standards, while the extreme classification applies to schemes designed to limit the impact of two or more elements removed, an extreme event, or Cascading.

The significant classification applies to a scheme for which a failure to operate or inadvertent operation of the scheme can result in non-consequential load loss greater than or equal to 300 MW, aggregate resource loss (tripping or runback of generation or HVdc) greater than the largest Real Power resource within the interconnection, loss of synchronism between two portions of the system, or negatively damped oscillations. The limited classification applies to a scheme for which a failure to operate or inadvertent operation would not result in a significant impact.

Applicability to Functional Model Entities

Three of the existing SPS-related reliability standards (PRC-012-0, PRC-013-0, and PRC-014-0) assign requirements to the Regional Reliability Organization. These standards are not mandatory and enforceable because FERC identified them as fill-in-the-blank standards in Order No. 693. This report recommends that requirements be reassigned to users, owners, and operators of the bulk power system in accordance with the NERC Functional Model. The following recommendations are included in the report:

- Review of new or modified SPS – assign to Reliability Coordinators and Planning Coordinators.
- SPS database maintenance – assign to Planning Coordinators; have Planning Coordinators submit databases to NERC for maintenance of a continent-wide database.
- Assessment of existing SPS – assign Planning Coordinators and Transmission Planners responsibility to include SPS assessments in annual transmission planning assessments; assign Reliability Coordinators responsibility to coordinate a periodic assessment of SPS design and coordination.

Revisions to Reliability Standards

Figure 1 provides a high-level overview of recommendations related to the six PRC standards that apply to SPS. Recommendations include consolidating the six existing standards into three standards.

- Combine all requirements pertaining to review, assessment, and documentation of SPS (presently in PRC-012-0, PRC-013-0, PRC-014-0, and PRC-015-0) in one new standard, PRC-012-1. The requirement in PRC-012-0 for regional procedures for reviewing SPS misoperations is superseded by recommendations for revisions to PRC-016-0.1. The requirement in PRC-012-0 for regional maintenance and testing requirements is superseded by PRC-005-2.
- Requirements pertaining to analysis and reporting of SPS misoperations should be revised in a new standard, PRC-016-1. Due to the significant difference between protection systems and SPS, the subject of SPS misoperations should not be included in a future revision of PRC-004.
- Requirements pertaining to maintenance and testing of SPS already have been translated to PRC-005-2 by the Project 2007-17 Protection System Maintenance & Testing drafting team.

Additional detail is provided in Table 2 in Appendix C – Mapping of Requirements from Existing Standards. This table summarizes the recommendations for how each requirement in the existing six SPS-related standards should be mapped to revised standards. The more significant recommendations are summarized below.

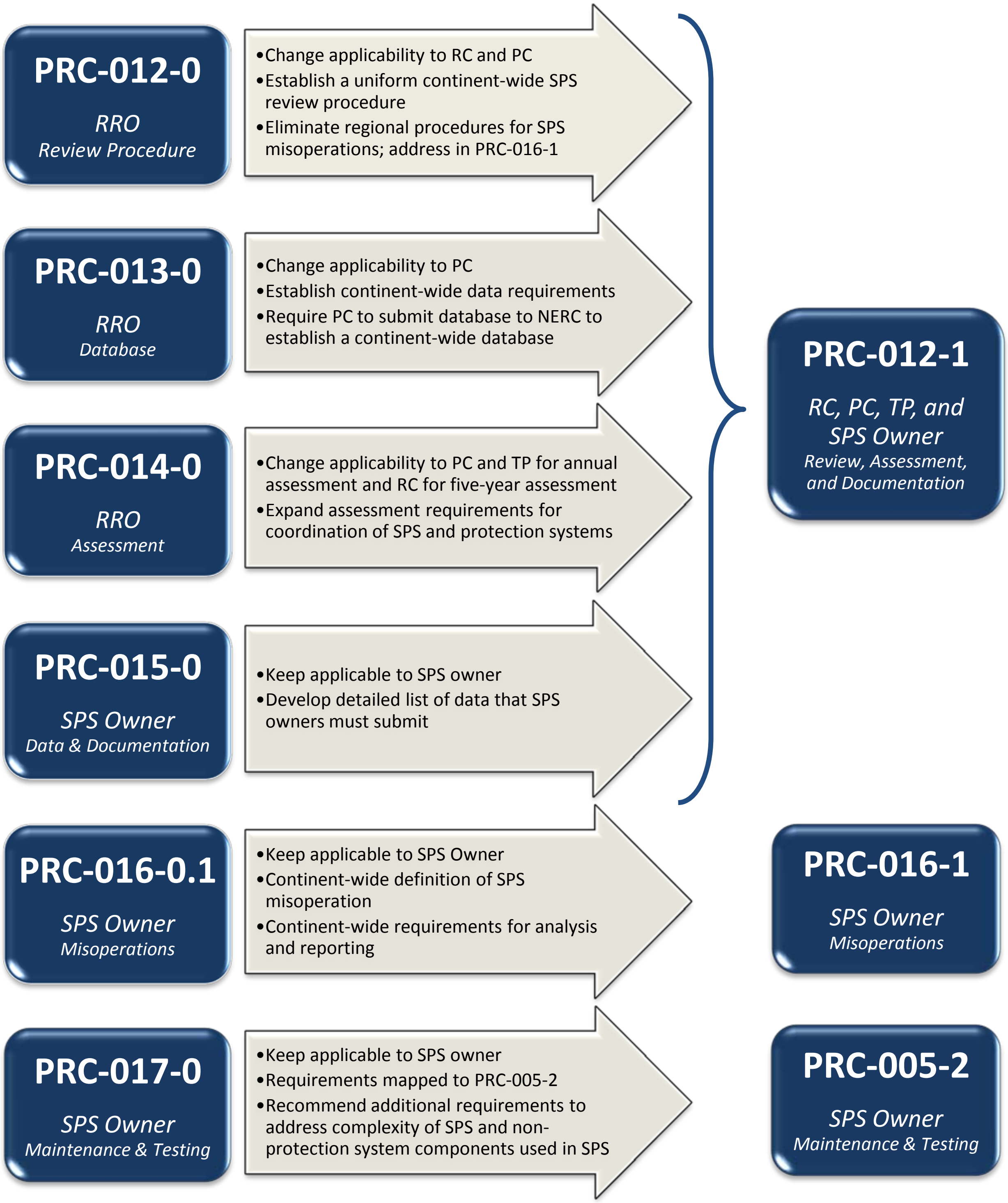


Figure 1 – Recommended Mapping of Existing PRC Standards

Standard PRC-012-1 – SPS Review, Assessment, and Documentation

- SPS owners should be required to design Type PL and Type PS SPS so that a single SPS component failure does not prevent the interconnected transmission system from meeting the performance requirements defined in NERC Reliability Standards TPL-001-0, TPL-002-0, or TPL-003-0.
- Existing requirements for regional procedures for reviewing new or modified SPS should be replaced with a continent-wide procedure assigned to Reliability Coordinators and Planning Coordinators to assure a wide-area view of both planning and operational aspects of SPS.
- Annual transmission planning assessments should include an assessment by the Planning Coordinator and Transmission Planner to review the operation, coordination, and effectiveness of SPS, including the effect of correct operation, a failure to operate, and inadvertent operations.
- Periodic comprehensive assessments (every five years or less) of SPS should be performed by the Reliability Coordinator, with support as requested from other entities, to assess whether SPS are still necessary, serves their intended purpose, meet relevant design criteria, coordinate with other SPS, UFLS, UVLS, and protection systems, and do not have unintended adverse consequences on reliability.
- Detailed continent-wide requirements for data submittals should be established for SPS owners proposing new or modified SPS. Detailed recommendations are included in this report.
- Planning Coordinators should be assigned responsibility for maintaining databases containing all information submitted by SPS owners. Planning Coordinators should be required to submit their databases to NERC so that NERC can maintain and make available a continent-wide SPS database.

Standard PRC-016-1 – SPS Misoperations

- PRC-016-1 should include a continent-wide definition of SPS misoperation based on the strawman definition proposed in this report.
- PRC-016-1 should include a continent-wide process for analysis of SPS operations and reporting SPS misoperations, including requirements for SPS owners to develop corrective action plans and provide analysis of SPS misoperations to Reliability Coordinators and Planning Coordinators.
- Reporting SPS operation and misoperation data for reliability metric purposes should be addressed outside PRC-016-1, in a manner similar to the process under development for reporting protection system misoperations in Project 2010-05.1 Protection Systems: Phase 1 (Misoperations).

Standard PRC-005-2 – Protection System Maintenance and Testing

- Maintenance and testing requirements for SPS should be expanded in the NERC Reliability Standards to address the complexity of testing SPS and the maintenance of non-protection system components used in SPS. These subjects should be addressed in a future revision of PRC-005 or development of a separate standard.

Recommendations to Be Included in Other Standards

This report discusses some aspects of SPS that are not addressed in the six SPS-related PRC standards. Recommendations should be incorporated in appropriate NERC Reliability Standards.

- SPS owners should be required to provide disturbance monitoring equipment to permit analysis of SPS performance following an event.
- Operating entities should be required to provide operators with documentation of procedures for operator interaction with SPS, and how operators should respond to SPS failures.
- All SPS should be monitored by SCADA/EMS with real-time status communicated that minimally includes whether the scheme is in-service, out-of-service, and the current operational state of the scheme.
- One entity should be assigned responsibility for monitoring, coordination, and control of an SPS.

Appendix A – Modeling and Simulation Considerations

The addition of two stable control systems does not necessarily result in a stable composite control system; the same is true for SPS. Although the SPS may not be directly linked in their actions, their composite actions and effect on the electric system for commonly-sensed system conditions or perturbations can often behave as a single control system. Therefore, it is imperative that they be evaluated for their potential to interact with each other, particularly during a system disturbance. The composite interaction of multiple SPS, or of SPS with UFLS, UVLS, or other protection systems could result in system instability or cascading.

Because of the complexity of some schemes, modeling them in system simulation is currently performed most often by monitoring their trigger conditions and manually mimicking their intended actions such as changing system configuration, switching reactive devices, and adjusting or tripping generation. Such manual manipulations in powerflow and dynamics studies are only effective when studying a single SPS unless an iterative process is used. Even then, manual manipulation may not be effective and may not be possible in studying the simultaneous actions of multiple SPS that could potentially interact with each other. The difficulty is most significant when considering the potential interaction of parameter-based SPS, since interaction with event-based SPS would occur only if the initial event and SPS operation caused a second event to occur.

It is sometimes possible to simulate the behavior of a single SPS through simulation tools such as user-defined scripts using vendor-provided or open-source programming capability, or standard relay models in the typical modeling and simulation software packages. However, doing so for the myriad of SPS that may exist, even in a portion of an interconnection, is cumbersome. Furthermore, simulating multiple SPS in real-time operations tools (e.g., EMS) for real-time contingency analysis is extremely difficult and often requires new and innovative algorithm and software development. In addition, models used in real-time systems are often abridged or reduced equivalents and may not permit accurate representation of a particular SPS's functions. All of these issues are extremely problematic given the sheer number of SPS in North American interconnections.

To assure SPS will function in a coordinated fashion may require that they be modeled and studied from their design inception in the planning horizon, through pre-seasonal system studies that determine transfer capabilities, and in the operating horizon from day-ahead planning through the real-time contingency analysis that system operators depend on for guidance. Present analysis methods are limited by the capability of the software tools and management of the SPS, and in some cases protection system, data. The industry should put emphasis on future developments in these areas.

General Considerations for Simulations

This section puts forth a number of factors, limitations, objectives, and overall guiding principles that a standard drafting team should consider in development of a new SPS standard with respect to the requirements for modeling and simulation, including data and process requirements necessary to support accurate and meaningful studies of SPS by Transmission Planners.

This report assumes that the modeling and simulation activities to be addressed are those performed for the planning horizon by Transmission Planning personnel. It is assumed that studies are performed using commercial off-the-shelf software packages and using databases derived from the interconnection-wide series of powerflow and dynamics cases. Studies using EMS based tools (e.g., study tools built into state estimators, real-time contingency analysis software, etc.) for real-time operations are not within the scope of this appendix.

It is important however, that the Transmission Planner share the results of planning horizon studies with operations personnel such that the impacts of SPS are effectively understood for the operating horizon also. This can be accomplished in a number of ways. Where operations support staff have similar study tools, sharing of the powerflow/dynamics cases, models, simulation scripts and similar data would enable them to evaluate SPS operation (or misoperation) for the operating horizon. Providing alarm or action limits for observable parameters (i.e., those that could be monitored in the operating environment) related to SPS operation would be another possibility. In this case, the parameters may be a direct indication or a proxy value that is indicative of the system condition of concern. Regardless of the process employed, the overriding consideration is that study results are adequately translated into actionable intelligence that is available to and understood by the system operator. While this is not intended to create a recommendation for a specific SPS standard requirement, how this would ultimately be accomplished should be kept in mind as SPS standards are developed and implemented.

As a general rule, SPS are conceived by transmission planning engineers and implemented by protection and control engineers. To some extent, the engineers in these two groups are concerned with different aspects of SPS operation and use different terminology to describe SPS (and other system) functions. For example, a transmission planner may consider a protection system component failure to be a contingency while a protection engineer may consider this to be a design consideration. Transmission planning engineers conceive an SPS as a solution to system-level problems. Their focus is on the "big picture" functional operation of the SPS for specific system level conditions. Protection and control engineers implement an SPS via detailed design using various sensors, relays, etc. Their focus is on efficiently implementing the functional requirements as they understand them to be. It is imperative that the planning engineers effectively communicate the requirements of the SPS to protection engineers and monitor the design and implementation of the scheme to ensure that the SPS is implemented and functions as prescribed by the planner.

The planning and protection engineers should also consult with the operations personnel to ensure that possible system-level events which might result in unintended SPS operation are considered. Involving operations personnel at each stage of the design process will help ensure that the range of operating conditions likely to be encountered in the real world (including outages), as well as practical operating considerations, are also adequately considered in the SPS design and implementation.

An explicit requirement should exist to represent the salient features of SPS operation in a form that can be readily shared with, understood by, and used in simulations by other Transmission Planners. Simulation of SPS in powerflow or dynamic studies may involve a combination of using standard relay models, various monitoring features, and scripts or program code to adequately simulate the functioning of the SPS. These may include user-defined scripts using vendor-provided or open-source programming capability, or standard relay models in the typical modeling and simulation software packages (either executed during solution-run time or as user-written dynamic models), etc. Transmission Planners generally have their own individual preferences as to how to reflect these functions when performing simulations. Additionally, different Transmission Planning organizations have different levels of expertise in developing scenarios to reflect actual system operation and performing simulations based on those scenarios. Therefore, it is important that the modeling information to be used by other Transmission Planning engineers as input (including run scripts) in simulations be simple, understandable and well documented. Any scripts or models provided need to be "open source" in nature and well-documented to enable independent verification. The use of user models, FORTRAN object code, compiled scripts, and similar which make it difficult for the receiving Transmission Planner to review and understand how the SPS model functions must be avoided.

In addition to providing the relay models, program code/script, and similar input as part of the database, a summary document should be provided explaining the SPS. The information shared must include a summary and guidance document which includes the following, as applicable.

- An overview explanation of the basic functioning of the SPS, describing when and how it operates
- A listing of the setpoints applicable to the SPS (e.g., relay trip settings, etc.)
- A summary overview of how the SPS is being simulated via relay models, simulation scripts that may be provided
- Specific bus numbers, branch identifiers, machine identifiers, etc. should be referenced to help the Transmission Planner receiving this information understand how the SPS is being simulated

SPS modeling information should be readily available as part of the interconnection-wide modeling processes, but not an integral part of an interconnection-wide case year database. Specific recommendations are included in the chapter on study and documentation requirements.

Because of the special nature of SPS, it is not practical or even possible to include them in the interconnection-wide load flow and/or dynamic database case years in the classic sense (e.g., such as one would include a generator or FACTS device model). Additionally, it is simply not necessary to model all SPS for all simulations. The reality is that an SPS in the Northeast will likely have very little impact on the results of simulations focused on the Southeast. Therefore, including all SPS in all simulations places an unreasonable burden on Transmission Planners. However, due consideration should be given to the interaction of a given SPS with other SPS. Note that geographical distance alone may not be sufficient justification not to consider the interaction of several SPS.

However, it is important that information about all SPS be available for use, as deemed appropriate by the Transmission Planners whose systems may be affected by the SPS operation (or misoperation). It is also important the relevant parameter-based SPS be modeled concurrently in simulations to appropriately evaluate potential interactions among the SPS.

Therefore, the data management process for providing SPS information for simulations purposes should include the following considerations.

- Sufficiently detailed SPS information and documentation as described above can be managed as part of the interconnection-wide powerflow and dynamic case creation process.
- Providing the models and simulation scripts alone is not sufficient. A functional description to assist the Transmission Planner in understanding how these modeling/simulation elements work to emulate the SPS function is necessary in order for the Transmission Planner to properly simulate and interpret the results of simulations involving the SPS.
- The SPS information may reside separately from the interconnection-wide powerflow and dynamic cases, but a clear association to each case must be evident.
- Each Transmission Planner will be able to select the SPS that are relevant to the simulation they are performing. Engineering judgment, with a documented reason, for excluding SPS from simulations is acceptable.
- Where included, the impact of multiple SPS and their interaction should be reasonably accounted for in the simulation activities.

It is envisioned that Transmission Planners will generally include only those SPS that, in their judgment, are relative to the simulations being performed and/or could potentially interact with other SPS being included in these simulations. However, it would be prudent to have some big picture check for unintended SPS interaction. Therefore, a joint, interconnection-wide study or assessment should be periodically performed to evaluate potential interactions among SPS across the entire interconnection. Such a study or assessment should include modeling and simulation of all of the SPS throughout the interconnection. A periodicity of five years for this joint study is suggested as an appropriate time frame.

Use of SPS Simulations in Transmission Planning Studies

SPS are used as alternatives to transmission infrastructure to support reliable system operation for identified concerns. As such, these schemes must be analyzed in transmission planning analyses just as any other transmission system addition would be, with a focus on:

- Operation as expected for the design case of concern
- Understanding the potential for operation beyond the original design intent
- Determining if there is a potential for failure to operate to rectify the design case of concern.

In system planning, the types of studies which are typically performed to determine system performance are powerflow and dynamic simulations and analyses. SPS need to be modeled in both of these types of studies.

Powerflow (i.e., steady-state) SPS modeling techniques which could be employed include:

- Explicit modeling of the SPS monitoring and consequent actions with scripting and programming automatically called during powerflow processing
- Explicit modeling of the actuation of the SPS in contingencies which are expected to cause the SPS to actuate
- Contingencies are included in the analysis with and without the SPS actuated
- Monitoring of system performance to determine if system conditions would actuate an SPS

  - The monitoring occurs for all contingencies examined
  - Any result indicating potential actuation of an SPS is rerun with the SPS actuated

Dynamic (i.e., stability) SPS modeling techniques which could be employed include:

- Explicit modeling of the SPS in the dynamic simulation with a model that includes the monitoring and consequent actions during the dynamic simulations
- Explicit modeling of the actuation of the SPS in contingencies which are expected to cause the SPS to actuate
- The dynamic/stability contingencies are included in the analysis with and without the SPS actuated
- Monitoring of SPS trigger elements (voltage, current, flow and/or frequency on system elements or element status) to determine if actuation of an SPS would have actuated
  - Rerun the simulation with the SPS actuated if the monitored results indicate potential actuation of the SPS

The SPS modeling techniques used in system planning should be based upon modeling information provided by the SPS owner which clearly describes what the SPS senses and the consequent actions taken when its triggering needs are met.

The need for accurate modeling information can be demonstrated with an example. In the example, two SPS exist in an area. One SPS trips a large generating plant for loss of a transmission circuit due to first swing stability concerns. This SPS acts within cycles of the initiating line loss. The second SPS inserts a series reactor into a transmission circuit to limit flow and eliminate an overload on the circuit. The second SPS acts within seconds (5 seconds for this example) of the overload condition occurring.

Steady state studies of the area where these SPS exist would examine the representative cases (sets of system conditions) and contingency sets for the study in question. If the power flow software allowed, a post-solution program could be run to test if the actuating circumstances for each SPS were met; if so, the contingent solution would be rerun and tested again for any other SPS which would actuate. If the power flow software did not have this flexibility, the engineer could include an SPS actuation for those contingencies expected to trigger the SPS and run that expanded contingency list; the results could be examined with attention paid to the loading for the circuit protected by the second SPS. Any contingencies which caused an overload on the triggering circuit could be rerun with the SPS actuated.

Since both SPS act within the dynamic simulation timeframe, the SPS should be modeled or monitored in stability simulations. Dynamic models could exist for both SPS. Should the flow on the SPS-triggering line exceed the flow actuation setpoint for the required time duration, the dynamic simulation would capture the impact of the reactor insertion and the SPS actuation. If the SPS were not explicitly modeled, their trigger values could be monitored (i.e., the status or flow on the line for the first SPS and the flow on the potentially overloaded circuit for the second SPS). The monitored data channels would be examined after each simulation to determine if the simulation needed to be rerun while modeling the appropriate SPS actions.

The goal for modeling SPS in studies is to confirm that they will operate to correct the intended system concerns as necessary to preserve acceptable system performance. In addition, the analyses provide understanding for system planning and operations on when and how the use of the SPS may change over time. This information may be critical for system operations staff to maintain reliable system operation.

Appendix B – Operational Considerations

This information is a high level list of important issues and concerns if performing SPS analyses in real-time operations.

Real-time SPS Evaluation

Current system conditions must be identified before evaluating whether an SPS would perform its function and achieve its desired outcome. Results of security analysis should be required to indicate whether an SPS should be armed (if armed manually) and whether an SPS will operate for a given contingency. Security analysis should model operation of the SPS in addition to the initiating contingency when the SPS is armed.

SPS evaluation often cannot be done with SCADA input alone. Some non-SCADA input may be needed; for example, limits from off-line studies are converted into inputs available in the Energy Management System (EMS). The inputs that support SPS evaluation and operation need to be codified in operating guides and presented on operator displays for ease of use and operation. Custom code and displays are generally required to aggregate all needed information for usage by engineers and operators in real time.

The impact of SPS operation on facilities external to the SPS owner/operator needs to be jointly considered and communicated to external entities and appropriately accounted for in EMS. Furthermore, the effects of external contingencies on the SPS triggers should be accounted for within EMS and known to operators.

SPS evaluation typically involves the testing of a limited set of relevant contingencies, requiring the use Real-Time Contingency Analysis (RTCA). In some cases, a dc solution to identify thermal issues is adequate; in other cases, a full ac solution is required (e.g., where triggers are voltage dependent).

Some EMS are not robust enough to compute ac solutions in EMS/RTCA. Depending on the classification of an SPS (e.g., significant), an EMS/RTCA with such limited capability would be insufficient to evaluate the impact of the SPS. In such cases it is necessary to establish other means, such as supplemental off-line tools or delegation of this analysis to an entity that has this capability, to study the operational impacts of the SPS.

If the EMS/RTCA does not reach a solved state, then the SPS cannot be evaluated. For example, some EMS/RTCA will fail to solve or fail to converge upon the creation of islands in the model. In these cases, SPS modeling may require custom software solutions.

Multiple Decision-Making Capability

When evaluating SPS in EMS/RTCA, intermediate steps must be modeled and intermediate states must be evaluated. It should be assumed that an SPS may suffer a full or partial failure and that system conditions will change as the SPS operates. Adverse conditions may arise during intermediate steps that lead to undesired outcomes or put the system into an unplanned operating state.

The post-contingency, pre-SPS-operation state must be known to assess system conditions before the SPS action can be evaluated. For example, the loss of a large nuclear station automatically activates a large emergency core cooling load. This new system state would require a re-solution to check post-contingent node voltage (i.e., with the load connected) before consideration of SPS activation and results can occur. This requires that several stages and intermediate actions be modeled in the evolution of the final system topology to ensure that the system can reach the desired end-state.

Information Management

Each SPS may have its own set of arming and activation triggers. Examples include equipment status, line loading and voltage. These triggers may be complex, and could affect the alarming capability required of EMS.

Changes to EMS models may require long lead times before an SPS can be implemented; for example, changes to models often require pushing through multiple staged software environments. Entities should use software designs that are flexible to accommodate timely changes to SPS models that might not be tied to the network model database release schedule. When implementing an SPS before the EMS model can be updated, it is necessary to establish other means, such as supplemental off-line tools or delegation of this analysis to an entity that has this capability, to study the operational impacts of the SPS.

Modeling Simplicity and Usability

Complex SPS schemes require due diligence to maintain and support. Entities should be required to develop and document an efficient approach to SPS control. An entity's strategy should allow for concurrent and/or consecutive SPS actions.

Appendix C – Mapping of Requirements from Existing Standards

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-012-0	R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include:	PRC-012-1 should define a continent-wide SPS review procedure conducted by the Reliability Coordinator and Planning Coordinator.	See Review and Approval of New or Modified SPS on pp. 16-17.
PRC-012-0	R1.1. Description of the process for submitting a proposed SPS for Regional Reliability Organization review.	PRC-012-1 should define a continent-wide SPS review procedure conducted by the Reliability Coordinator and Planning Coordinator.	See Review and Approval of New or Modified SPS on pp. 16-17.
PRC-012-0	R1.2. Requirements to provide data that describes design, operation, and modeling of an SPS.	PRC-012-1 should define continent-wide requirements for SPS owners to provide data that is clear and understandable to all entities that require this information to plan and operate the bulk power system.	See Data Submittals by Entities that Own SPS on pp. 18-19.
PRC-012-0	R1.3. Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS 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.	PRC-012-1 should require that all Type PS and PL SPS are designed so system performance requirements are met in the event of a single component failure within the SPS.	See SPS Single Component Failure Requirements on p. 14-15

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-012-0	R1.4. Requirements to demonstrate that the inadvertent operation of an SPS 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.	PRC-012-1 should require that an entity proposing a new or modified SPS should be required to submit studies that demonstrate the operation, coordination, and effectiveness of the SPS, including the impacts of a correct operation, a failure to operate, and inadvertent operation.	See Review and Approval of New or Modified SPS on p. 16.
PRC-012-0	R1.5. Requirements to demonstrate the proposed SPS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.	PRC-012-1 should require that an entity proposing a new or modified SPS should be required to submit studies that demonstrate the operation, coordination, and effectiveness of the SPS, including the impacts of a correct operation, a failure to operate, and inadvertent operation.	See Review and Approval of New or Modified SPS on p. 16.
PRC-012-0	R1.6. Regional Reliability Organization definition of misoperation.	A continent-wide definition of an SPS misoperation should be established.	See SPS Misoperation Definition on p. 22.
PRC-012-0	R1.7. Requirements for analysis and documentation of corrective action plans for all SPS misoperations.	Do not carry forward to revised standards.	The need for this requirement is eliminated by establishing continent-wide requirements in PRC-016-1. See SPS Operation Review Process on pp. 23-24.
PRC-012-0	R1.8. Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure.	Do not carry forward to revised standards.	The need for this requirement is eliminated by establishing a continent-wide review procedure within PRC-012-1. See Review and Approval of New or Modified SPS on pp. 16-17.
PRC-012-0	R1.9. Determination, as appropriate, of maintenance and testing requirements.	Do not carry forward to revised standards.	The need for this requirement is eliminated by establishing continent-wide maintenance and testing requirements within PRC-005-2.

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-012-0	R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its SPS review procedure on request (within 30 calendar days).	Do not carry forward to revised standards.	Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information.
PRC-013-0	R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with an SPS installed shall maintain an SPS database. The database shall include the following types of information:	PRC-012-1 should require that each Planning Coordinator maintain a database, and provide the database to NERC for the purpose of maintaining a continent-wide database.	See SPS Database on p. 19.
PRC-013-0	R1.1. Design Objectives — Contingencies and system conditions for which the SPS was designed,	This information is included in a comprehensive list of data requirements to be provided by the SPS owner and maintained in a database by the Planning Coordinator.	See Data Submittals by Entities that Own SPS on pp. 18-19 and SPS Database on p. 19.
PRC-013-0	R1.2. Operation — The actions taken by the SPS in response to Disturbance conditions, and	This information is included in a comprehensive list of data requirements to be provided by the SPS owner and maintained in a database by the Planning Coordinator.	See Data Submittals by Entities that Own SPS on pp. 18-19 and SPS Database on p. 19.
PRC-013-0	R1.3. Modeling — Information on detection logic or relay settings that control operation of the SPS.	This information is included in a comprehensive list of data requirements to be provided by the SPS owner and maintained in a database by the Planning Coordinator.	See Data Submittals by Entities that Own SPS on pp. 18-19 and SPS Database on p. 19.

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-013-0	R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).	Do not carry forward to revised standards.	Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information.
PRC-014-0	R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all SPSs installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.	PRC-012-1 should require the Planning Coordinator and Transmission Planner to assess SPS in annual transmission planning assessments and require the Reliability Coordinator to conduct a periodic review every five years, or sooner if significant changes are made to the system topology or operating characteristics that may impact the coordination among SPS and between SPS and UFLS, UVLS, and other protection systems.	See Periodic Comprehensive Assessments of SPS Coordination on p. 17.
PRC-014-0	R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all SPSs installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).	Do not carry forward to revised standards.	Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information.
PRC-014-0	R3. The documentation of the Regional Reliability Organization's SPS assessment shall include the following elements:	PRC-012-1 should require the Reliability Coordinator to document its periodic assessments. The documentation should include the same elements required in a study supporting approval of a new or modified SPS.	See Review and Approval of New or Modified SPS on pp. 16-17 and Assessment of Existing SPS on p. 17.
PRC-014-0	R3.1. Identification of group conducting the assessment and the date the assessment was performed.	This list of elements includes: • Entity conducting the study • Study completion date	See Review and Approval of New or Modified SPS on pp. 16-17.

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-014-0	R3.2. Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.	This list of elements includes: • Study years • System conditions • Contingencies analyzed • Study completion date	See Review and Approval of New or Modified SPS on pp. 16-17.
PRC-014-0	R3.3. Identification of SPSs that were found not to comply with NERC standards and Regional Reliability Organization criteria.	PRC-012-1 should require the Planning Coordinator and Transmission Planner document and submit any issues identified in the annual assessment to the Reliability Coordinator. PRC-012-1 should require the Reliability Coordinator to document and submit any issues identified in the periodic assessment to the SPS owner.	See Assessment of Existing SPS on p. 17.
PRC-014-0	R3.4. Discussion of any coordination problems found between a SPS and other protection and control systems.	PRC-012-1 should require the Reliability Coordinator to request the Planning Coordinator and Transmission Planner to assess and document whether the SPS is still necessary, serves its intended purpose, meets performance criteria, coordinates with other SPS, UFLS, UVLS, and protection systems, and does not have unintended adverse consequences on reliability.	See Periodic Comprehensive Assessments of SPS Coordination on p. 17.
PRC-014-0	R3.5. Provide corrective action plans for non-compliant SPSs.	PRC-012-1 should require that if issues are identified in an annual or periodic assessment, the Reliability Coordinator and Planning Coordinator determine, in consultation with the SPS owner, whether a corrective action plan is required, and if so, whether the SPS can remain in service until a corrective action plan is implemented. If a corrective action plan is required, PRC-012-1 should require the SPS owner to submit an application for a new or modified SPS.	See Assessment of Existing SPS on p. 17.

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-015-0	R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed SPSs as specified in Reliability Standard PRC-013-0_R1.	PRC-012-1 should define continent-wide requirements for SPS owners to provide data that is clear and understandable to all entities that require this information to plan and operate the bulk power system.	See Data Submittals by Entities that Own SPS on pp. 18-19.
PRC-015-0	R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.	Do not carry forward to revised standards. PRC-012-1 should have a requirement for the SPS owner to file an application for approval of an SPS, which assures that the SPS is reviewed in accordance with the continent-wide review procedure prior to being placed in service.	See Review and Approval of New or Modified SPS on pp. 16-17.
PRC-015-0	R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of Studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).	Do not carry forward to revised standards.	Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information.
PRC-016-0.1	R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all misoperations in accordance with the Regional SPS review procedure specified in Reliability Standard PRC-012-0_R1.	PRC-016-1 should establish a continent-wide process for analyzing and reporting SPS misoperations.	See SPS Operation Review Process on pp. 23-24.

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-016-0.1	R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations.	PRC-016-1 should establish a requirement that the SPS owner should be required to develop and implement a corrective action plan for SPS misoperations.	See SPS Operation Review Process on pp. 23-24.
PRC-016-0.1	R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).	Do not carry forward to revised standards.	Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information.
PRC-017-0[21]	R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place. The program(s) shall include:	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, R1.
PRC-017-0	R1.1. SPS identification shall include but is not limited to:	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, Tables 1-1 – 1-5, and Table 2.
PRC-017-0	R1.1.1. Relays.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, Table 1-1.
PRC-017-0	R1.1.2. Instrument transformers.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, Table 1-3.
PRC-017-0	R1.1.3. Communications systems, where appropriate.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, Table 1-2.

[21] Mapping for requirements in PRC-017-0 are adapted from the mapping document developed by the Project 2007-17 Protection System Maintenance & Testing drafting team.

Table 2: Mapping of SPS-Related Requirements in Existing NERC Reliability Standards			
Existing Standard	**Requirement**	**Proposal**	**Comments**
PRC-017-0	R1.1.4. Batteries.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, Table 1-4.
PRC-017-0	R1.2. Documentation of maintenance and testing intervals and their basis.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, R1 and R2.
PRC-017-0	R1.3. Summary of testing procedure.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, R1, Tables 1-1 – 1-5, and Table 2.
PRC-017-0	R1.4. Schedule for system testing.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, R1 and R2.
PRC-017-0	R1.5. Schedule for system maintenance.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, R1 and R2
PRC-017-0	R1.6. Date last tested/maintained.	Addressed by Project 2007-17, Protection System Maintenance and Testing	See PRC-005-2, R3 and associated Measures, R4 and associated Measure, and Data Retention.
PRC-017-0	R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).	Addressed by Project 2007-17, Protection System Maintenance and Testing; this requirement is not carried forward to the revised standard.	Existing reporting requirements that have no discernible impact on promoting the reliable operation of the bulk electric system are being removed from NERC Reliability Standards in Project 2013-02 Paragraph 81. The ERO Rules of Procedures, Section 401: 3. Data Access, provide the ability for NERC to obtain this information.

Appendix D – Standards Committee Request for Research; January 9, 2011

Request for Research

Project 2010-05.2

Phase 2 of Protection Systems: SPS and RAS

Introduction

NERC's Standards Committee has tentatively identified this project for initiation in late 2012. Prior to then, there is a need for additional research and scoping of the project to determine:

- What is the problem that this project will try to solve?
- Is the development of a standard the appropriate manner to solve that problem, or should alternative approaches be used?
- If a standard is appropriate, what is the recommended solution to the problem?

Results based standards projects use the approach of defining the needs, goals, and objectives for the project. For this project, we would like your assistance in this effort. Below is a draft problem statement for your consideration.

Need (Problem)

Special Protection Systems (SPS) and Remedial Action Schemes (RAS) can misoperate and negatively impact the reliability of the BES.

Does the need above correctly document the concern described in the attached draft SAR?

Do you agree that this is a problem that needs to be addressed?

Is a standard the appropriate vehicle to address this problem, or should an alternative approach be used? If an alternative, is recommended, what would that alternative be?

If development of a standard is appropriate, then please consider the following Goal

Goal (Solution)

Require the analysis, reporting, and correction of Misoperations of SPS and RAS.

Request

Please provide the Standards Committee with the following information:

- An updated Need/Problem (or a statement of concurrence with the draft presented here)
- A statement indicating whether or not you believe this problem is one which needs to be addressed
- If you agree the problem needs to be addressed, a suggestion for how to address the problem
- If you suggest a standard be developed to address the problem, then please provide
    - An updated goal (or a statement of concurrence with the draft presented here)
    - A set of objectives in support of that goal
    - If you have any suggested changes to the attached draft SAR, please propose them
    - If you have specific recommendations for requirements language or additional information, please include them

Thank you in advance for your assistance.

Appendix E – Scope of Work Approved by the Planning Committee; June 8, 2011

Assessment of Special Protection System Standards and Regional Practices

Proposal:

The SPCS proposes to conduct an assessment of the SPS-related PRC standards and definition of SPS, conduct an assessment of existing regional practices summarizing commonality and differences, and to document its findings in a report to the Planning Committee that can serve as a reference document for a standard drafting team that ultimately will be assigned to review these standards. If deemed appropriate, the report could be used to support a Compliance Application Notice (CAN) to address part of this issue until a revised definition and standard(s) are developed. The SPCS further proposes this activity should be a joint effort with the Transmission Issues Subcommittee (TIS).

Rationale:

- The SPCS scope calls for providing subject matter expertise for NERC Standards related to protection systems and controls, and the SPCS work plan includes an assignment to review all existing PRC-series Reliability Standards, to advise the Planning Committee of its assessment, and to develop Standards Authorization Requests, as appropriate, to address any perceived deficiencies.
- The SPCS has reviewed all PRC standards except the group of SPS standards. The SPCS had started assessment of these standards, but the assessment was deferred due to other priority work such as the Power Plant and Transmission System Protection Coordination technical reference document.
- The SPCS has reviewed its work plan and determined that this is the next logical project for the SPCS. Work on the Transmission System Phase Backup Protection reliability guideline is wrapping up at this time and the SPCS can make the SPS review one of two priority activities for this year (the other is the document addressing operation of protection systems in response to power swings).
- The SPCS believes that a thorough review of SPS-related PRC standards would benefit from the expertise of TIS and the SPCS recommends a joint SPCS/TIS effort coordinated by the SPCS. This proposal has been reviewed with and is supported by TIS.
- The SPCS proposes to conduct an assessment of the standards and definition of SPS, and conduct an assessment of existing regional practices summarizing commonality and differences among the various regional practices.
- The SPCS believes that differences among regional practices must be resolved through a formal process; a consensus opinion of what constitutes an SPCS would lack standing unless it is vetted through a stakeholder process. The SPCS proposes to document its findings in a report that can serve as a reference document for a standard drafting team that ultimately will be assigned to review these standards. If deemed appropriate, the report could be used to support a CAN to address part of this issue until a revised standard(s) is developed.
- The scope of work for such a review is significant and direction should come through the NERC Planning Committee as the body to which SPCS and TIS report.
- The SPCS believes that an appropriate time frame for completing this report would be to submit a draft to the Planning Committee at its March 2012 meeting. The SPCS and TIS believe this schedule is appropriate to support a thorough review.

Approved by the NERC Planning Committee
June 8, 2011

Appendix F – System Analysis and Modeling Subcommittee Roster

John Simonelli
Chair
Director - Operations Support Services
ISO New England

K. R Chakravarthi
Vice Chair
Manager, Interconnection and Special Studies
Southern Company Services, Inc.

G Brantley Tillis, P.E.
RE – FRCC
Manager, Transmission Planning Florida
Progress Energy Florida

Kiko Barredo
RE – FRCC – Alternate
Manager, Bulk Transmission Planning
Florida Power & Light Co.

Thomas C. Mielnik
RE – MRO
Manager Electric System Planning
MidAmerican Energy Co.

Salva R. Andiappan
RE – MRO – Alternate
Manager - Modeling and Reliability Assessments
Midwest Reliability Organization

Donal Kidney
RE – NPCC
Manager, System Compliance Program Implementation
Northeast Power Coordinating Council

Bill Harm
RE – RFC
Senior Consultant
PJM Interconnection, L.L.C.

Mark Byrd
RE – SERC
Manager - Transmission Planning
Progress Energy Carolinas

Gary T Brownfield
RE – SERC – Alternate
Supervising Engineer, Transmission Planning
Ameren Services

Jonathan E Hayes
RE – SPP
Reliability Standards Development Engineer
Southwest Power Pool, Inc.

Kenneth A. Donohoo
RE – TRE
Director System Planning
Oncor Electric Delivery

Hari Singh
RE – WECC
Transmission Asset Management
Xcel Energy, Inc.

Kent Bolton
RE – WECC – Alternate
Staff Engineer
Western Electricity Coordinating Council

Digaunto Chatterjee
ISO/RTO
Manager of Transmission Expansion Planning
Midwest ISO, Inc.

Patricia E Metro
Cooperative
Manager, Transmission and Reliability Standards
National Rural Electric Cooperative Association

Eric Mortenson, P.E.
Investor-Owned Utility
Principal Rates & Regulatory Specialist
Exelon Business Services Company

Amos Ang, P.E.
Investor-Owned Utility
Engineer, Transmission Interconnection Planning
Southern California Edison

Bob Cummings
NERC Staff Coordinator
Senior Performance and Analysis Engineer
NERC

Appendix G – System Protection and Control Subcommittee Roster

William J. Miller
Chair
Principal Engineer
Exelon Corporation

Philip B. Winston
Vice Chair
Chief Engineer, Protection and Control
Southern Company

Michael Putt
RE – FRCC
Manager, Protection and Control Engineering Applications
Florida Power & Light Co.

Mark Gutzmann
RE – MRO
Manager, System Protection Engineering
Xcel Energy, Inc.

Richard Quest
RE – MRO – Alternate
Principal Systems Protection Engineer
Midwest Reliability Organization

George Wegh
RE – NPCC
Manager
Northeast Utilities

Quoc Le
RE – NPCC -- Alternate
Manager, System Planning and Protection
NPCC

Jeff Iler
RE – RFC
Principal Engineer, Protection and Control Engineering
American Electric Power

Therron Wingard
RE – SERC
Principal Engineer
Southern Company

David Greene
RE – SERC -- Alternate
Reliability Engineer
SERC Reliability Corporation

Lynn Schroeder
RE – SPP
Manager, Substation Protection and Control
Westar Energy

Samuel Francis
RE – TRE
System Protection Specialist
Oncor Electric Delivery

David Penney, P.E.
RE – TRE – Alternate
Senior Reliability Engineer
Texas Reliability Entity

Baj Agrawal
RE – WECC
Principal Engineer
Arizona Public Service Company

Miroslav Kostic
Canada Provincial
P&C Planning Manager, Transmission
Hydro One Networks, Inc.

Sungsoo Kim
Canada Provincial
Section Manager – Protections and Technical Compliance
Ontario Power Generation Inc.

Michael J. McDonald
Investor-Owned Utility
Principal Engineer, System Protection
Ameren Services Company

Jonathan Sykes
Investor-Owned Utility
Manager of System Protection
Pacific Gas and Electric Company

Charles W. Rogers
Transmission Dependent Utility
Principal Engineer
Consumers Energy Co.

Joe T. Uchiyama
U.S. Federal
Senior Electrical Engineer
U.S. Bureau of Reclamation

Daniel McNeely
U.S. Federal – Alternate
Engineer - System Protection and Analysis
Tennessee Valley Authority

Philip J. Tatro
NERC Staff Coordinator
Senior Performance and Analysis Engineer
NERC

Appendix H – Additional Contributors

Forrest Brock
Transmission Compliance Specialist
Western Farmers Electric Cooperative

Robert Creighton
Sr. Engineering Specialist, Transmission Planning
Nova Scotia Power, Inc.

Tom Gentile
Senior Director, Transmission Northeast
Quanta Technology

Bryan Gwyn
Senior Director, Protection and Control Asset Management
Quanta Technology

Gene Henneberg
Staff Protection Engineer
NV Energy

Greg Henry (formerly NERC Staff Coordinator for SAMS)
Lead Engineer, Smart Integrated Infrastructure
Black & Veatch

Bobby Jones
Planning Manager – Stability
Southern Company Services

John O'Connor
Principal Engineer
Progress Energy Carolinas

Slobodan Pajic
Senior Engineer, Energy Consulting
GE Energy Management

Appendix I – Revision History

Revision History		
Version	**Date**	**Modification(s)**
0	March 5, 2013	Initial Document
0.1	April 18, 2013	Appendix A – Correction to remove trade names and replace with generic language in the section, General Considerations for Simulation

A. Introduction

1. **Title:** **Remedial Action Scheme Review Procedure**

2. **Number:** PRC-012-1

3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Effective Date:** See Implementation Plan for the Revised Definition of "Remedial Action Scheme"

B. Requirements

R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include:

R1.1. Description of the process for submitting a proposed RAS for Regional Reliability Organization review.

R1.2. Requirements to provide data that describes design, operation, and modeling of a RAS.

R1.3. 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.

R1.4. Requirements to demonstrate 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.

R1.5. Requirements to demonstrate the proposed RAS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.

R1.6. Regional Reliability Organization definition of misoperation.

R1.7. Requirements for analysis and documentation of corrective action plans for all RAS misoperations.

R1.8. Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure.

R1.9. Determination, as appropriate, of maintenance and testing requirements.

R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Provider using or planning to use a RAS shall have a documented Regional review procedure as defined in Reliability Standard PRC-012-1_R1.

M2. The Regional Reliability Organization shall have evidence it provided affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of the Regional Reliability Organization’s procedure is missing one of the items listed in Reliability Standard PRC-012-1_R1.

2.2. Level 2: Documentation of the Regional Reliability Organization’s procedure is missing two of the items listed in Reliability Standard PRC-012-1_R1.

2.3. Level 3: Documentation of the Regional Reliability Organization’s procedure is missing three of the items listed in Reliability Standard PRC-012-1_R1.

2.4. Level 4: Documentation of the Regional Reliability Organization’s procedure was not provided or is missing four or more of the items listed in Reliability Standard PRC-012-1_R1.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard PRC-012-1 — Remedial Action Scheme Review Procedure

United States

Standard	Requirement	Enforcement Date	Inactive Date
PRC-012-1	All		

This standard has not yet been approved by the applicable regulatory authority.

A. Introduction

1. **Title:** **Remedial Action Scheme Database**

2. **Number:** PRC-013-1

3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems.

4. **Applicability:**

   4.1. Regional Reliability Organization

5. **Effective Date:** See Implementation Plan for the Revised Definition of "Remedial Action Scheme"

B. Requirements

R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a RAS installed shall maintain a RAS database. The database shall include the following types of information:

R1.1. Design Objectives — Contingencies and system conditions for which the RAS was designed,

R1.2. Operation — The actions taken by the RAS in response to Disturbance conditions, and

R1.3. Modeling — Information on detection logic or relay settings that control operation of the RAS.

R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Providers with a RAS installed, shall have a RAS database as defined in PRC-013-1_R1 of this Reliability Standard.

M2. The Regional Reliability Organization shall have evidence it provided documentation of its database or the information therein, to affected Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: NERC.

   1.2. Compliance Monitoring Period and Reset Timeframe

   On request (within 30 calendar days.)

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. Levels of Non-Compliance

2.1. Level 1: The Regional Reliability Organization's database is missing one of the items listed in Reliability Standard PRC-013-1_R1.

2.2. Level 2: The Regional Reliability Organization's database is missing two of the items listed in Reliability Standard PRC-013-1_R1.

2.3. Level 3: Not applicable.

2.4. Level 4: The Regional Reliability Organization's database was not provided or is missing all of the elements listed in Reliability Standard PRC-013-1_R1.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Dave	New
1	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard PRC-013-1 — Remedial Action Scheme Database

United States

Standard	Requirement	Enforcement Date	Inactive Date
PRC-013-1	All		

This standard has not yet been approved by the applicable regulatory authority.

A. Introduction

1. **Title:** **Remedial Action Scheme Assessment**
2. **Number:** PRC-014-1
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
   - **4.1.** Regional Reliability Organization
5. **Effective Date:** See Implementation Plan for the Revised Definition of "Remedial Action Scheme"

B. Requirements

R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.

R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all RAS installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).

R3. The documentation of the Regional Reliability Organization's RAS assessment shall include the following elements:

- **R3.1.** Identification of group conducting the assessment and the date the assessment was performed.
- **R3.2.** Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.
- **R3.3.** Identification of RAS that were found not to comply with NERC standards and Regional Reliability Organization criteria.
- **R3.4.** Discussion of any coordination problems found between a RAS and other protection and control systems.
- **R3.5.** Provide corrective action plans for non-compliant RAS.

C. Measures

M1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC standards and Regional criteria.

M2. The Regional Reliability Organization shall provide either a summary report or a detailed report of this assessment to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).

M3. The Regional Reliability Organization's documentation of the RAS assessment shall include all elements as defined in Reliability Standard PRC-014-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The summary (or detailed) Regional RAS assessment is missing one of the items listed in Reliability Standard PRC-014-1_R3.

2.2. Level 2: The summary (or detailed) Regional RAS assessment is missing two of the items listed in Reliability Standard PRC-014-1_3.

2.3. Level 3: The summary (or detailed) Regional RAS assessment is missing three of the items listed in Reliability Standard PRC-014-1_R3.

2.4. Level 4: The summary (or detailed) Regional RAS assessment is missing more than three of the items listed in Reliability Standard PRC-014-1_R3 or was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard PRC-014-1 — Remedial Action Scheme Assessment

United States

Standard	Requirement	Enforcement Date	Inactive Date
PRC-014-1	All		

This standard has not yet been approved by the applicable regulatory authority.

A. Introduction

1. **Title:** **Remedial Action Scheme Data and Documentation**

2. **Number:** PRC-015-1

3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.

4. **Applicability:**

   4.1. Transmission Owner that owns a RAS

   4.2. Generator Owner that owns a RAS

   4.3. Distribution Provider that owns a RAS

5. **Effective Date:** See Implementation Plan for the Revised Definition of "Remedial Action Scheme"

B. Requirements

R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall maintain a list of and provide data for existing and proposed RAS as specified in Reliability Standard PRC-013-1 R1.

R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-1_R1 prior to being placed in service.

R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of RAS data and the results of Studies that show compliance of new or functionally modified RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

C. Measures

M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it maintains a list of and provides data for existing and proposed RAS as defined in Reliability Standard PRC-013-1_R1.

M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-1_R1 prior to being placed in service.

M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of RAS data and the results of studies that show compliance of new or functionally modified RAS with NERC standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: RAS owners provided RAS data, but was incomplete according to the Regional Reliability Organization RAS database requirements.

2.2. Level 2: RAS owners provided results of studies that show compliance of new or functionally modified RAS with the NERC Planning Standards and Regional Reliability Organization criteria, but were incomplete according to the Regional Reliability Organization procedures for Reliability Standard PRC-012-1_R1.

2.3. Level 3: Not applicable.

2.4. Level 4: No RAS data was provided in accordance with Regional Reliability Organization RAS database requirements for Standard PRC-012-1_R1, or the results of studies that show compliance of new or functionally modified RAS with the NERC Reliability Standards and Regional Reliability Organization criteria were not provided in accordance with Regional Reliability Organization procedures for Reliability Standard PRC-012-1_R1.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
1	November 19, 2015	FERC Order issued approving PRC-015-1. Docket No. RM15-13-000.	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard PRC-015-1 — Remedial Action Scheme Data and Documentation

United States

Standard	Requirement	Enforcement Date	Inactive Date
PRC-015-1	All	04/01/2017	

A. Introduction

1. **Title: Remedial Action Scheme Misoperations**

2. **Number:** PRC-016-1

3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.

4. **Applicability:**

   4.1. Transmission Owner that owns a RAS.

   4.2. Generator Owner that owns a RAS.

   4.3. Distribution Provider that owns a RAS.

5. **Effective Date:** See Implementation Plan for the Revised Definition of "Remedial Action Scheme"

B. Requirements

R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall analyze its RAS operations and maintain a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-1_R1.

R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall take corrective actions to avoid future misoperations.

R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).

C. Measures

M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it analyzed RAS operations and maintained a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-1_R1.

M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it took corrective actions to avoid future misoperations.

M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of the misoperation analyses and the corrective action plans to the affected Regional Reliability Organization and NERC on request (within 90 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

On request [within 90 calendar days of the incident or on request (within 30 calendar days) if requested more than 90 calendar days after the incident.]

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of RAS misoperations is complete but documentation of corrective actions taken for all identified RAS misoperations is incomplete.

2.2. Level 2: Documentation of corrective actions taken for RAS misoperations is complete but documentation of RAS misoperations is incomplete.

2.3. Level 3: Documentation of RAS misoperations and corrective actions is incomplete.

2.4. Level 4: No documentation of RAS misoperations or corrective actions.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	July 3, 2007	Change reference in Measure 1 from “PRC-016-0_R1” to “PRC-012-1_R1.”	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date	Revised
1	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

1	November 19, 2015	FERC Order issued approving PRC-016-1. Docket No. RM15-13-000.	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard PRC-016-1 — Remedial Action Scheme Misoperations

United States

Standard	Requirement	Enforcement Date	Inactive Date
PRC-016-1	All	04/01/2017	

Standards Announcement

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)
PRC-012-2

Informal Comment Period Open through May 20, 2015

Now Available

A 21-day informal comment period for **PRC-012-2 – Remedial Action Schemes** is open through **8 p.m. Eastern, Wednesday, May 20, 2015**.

For this informal posting, the drafting team is soliciting stakeholder feedback on the scope and work product developed thus far. The drafting team will use the informal feedback to finalize the preliminary draft of PRC-012-2. Stakeholders may communicate additional feedback directly to the drafting team through its open meetings leading up to the first formal posting. The next meeting is scheduled for June 8-11, 2015. Meeting details will be posted to the NERC calendar early May 2015.

Background

This project is addressing all aspects of Remedial Action Schemes (RAS) and Special Protection Systems (SPS) contained in the RAS/SPS-related Reliability Standards: PRC-012-1, PRC-013-1, PRC-014-1, PRC-015-1, and PRC-016-1. The maintenance of the Protection System components associated with RAS (PRC-017-1 Remedial Action Scheme Maintenance and Testing) are already addressed in PRC-005-2. PRC-012-2 addresses the testing of the non-Protection System components associated with RAS/SPS.

In FERC Order No. 693 (dated March 16, 2007), the Commission identified PRC-012-0, PRC-013-0, and PRC-014-0 as “fill-in-the-blank” standards and did not approve or remand them because they are applicable to the Regional Reliability Organizations (RROs), assigning the RROs the responsibility to establish regional procedures and databases, and to assess and document the operation, coordination, and compliance of RAS/SPS. The deference to regional practices precludes the consistent application of RAS/SPS-related Reliability Standard requirements.

The proposed draft of PRC-012-2 corrects the applicability of the fill-in-the-blank standards by assigning the requirement responsibilities to the specific users, owners, and operators of the Bulk-Power System; and incorporates the reliability objectives of all the RAS/SPS-related standards.

Commenting

Use the electronic form to submit comments on the standard. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Survey Report

Survey Details

Name 2010-05.3 Phase 3 of Protections Systems: RAS | PRC-012-2

Description

4/30/2015

Start Date

End Date

5/20/2015

Associated Ballots

Survey Questions

1. RAS review and approval (Requirements R1, R2 and R3): Do you agree that RAS should be reviewed and approved by an independent party prior to placing the RAS in-service? If no, please state the basis for your disagreement and an alternative approach.

Yes

No

2. Information listed in Attachment 1 (Requirement R1): Do you agree that the RAS information required in Attachment 1 is a comprehensive list? If no, please identify what other information you think is necessary for a thorough RAS review.

Yes

No

3. Choice of Reliability Coordinator (Requirements R1, R2 and R3): Do you agree with the Reliability Coordinator being the functional entity designated to review the RAS? If no, please provide the basis for your disagreement, your choice of functional entity to conduct the reviews, and the rationale for your choice.

Yes

No

4. Checklist in Attachment 2 (Requirement R2): Do you agree that the checklist in Attachment 2 provides a comprehensive guide for the Reliability Coordinator to facilitate a thorough RAS review? If no, please identify what other reliability-related considerations should be included in Attachment 2 and the rationale for your choice.

Yes

No

5. Choice of Transmission Planner (Requirement R4): The Transmission Planner is required to perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, as well as the BES performance following an inadvertent operation of the RAS. Do you agree with the Transmission Planner being the functional entity designated to evaluate the RAS? If no, please provide the basis for

your disagreement, your choice of functional entity to conduct the evaluations, and the rationale for your choice.

Yes

No

6. No RAS Classification (Requirement R4): The drafting team considered the RAS classification systems used by several Regions to be rooted in PRC-012, Requirement R1, R1.4. which reads: "Requirements to demonstrate 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." Although, the drafting team is not proposing to use formal RAS classifications, the intent of PRC-012, Requirement R1, R1.4. is retained in Requirement 4 and Attachment 1. Do you agree that the language of Requirement R4, its Parts, and Attachment 1 accomplish the objectives of RAS "classification" without having a formal RAS classification system in the standard? If no, please provide the basis for your disagreement and describe an alternate proposal.

Yes

No

7. RAS Operational Analyses (Requirement R6): Requirement R6 mandates each RAS-owner analyze each RAS operation or failure of a RAS to operate to identify performance deficiencies Do you agree that the application of Requirement R6 and its Parts would identify performance deficiencies in RAS? If

no, please provide the basis for your disagreement and an alternate proposal.

Yes

No

8. Corrective Action Plans (Requirements R5, R7, and R8): Do you agree that the application of Requirements R5, R7, and R8 would address the reliability objectives associated with CAPs? If no, please provide the basis for your disagreement and describe an alternate proposal.

Yes

No

9. Functional Testing of RAS (Requirement R9): Do you agree that functional testing of each RAS would verify the overall RAS performance and the proper operation of non-Protection System components? If no, please provide the basis for your disagreement and describe an alternate proposal.

Yes

No

10. Choice of Reliability Coordinator (Requirement R10): Do you agree with the Reliability Coordinator being the functional entity designated to maintain the RAS database? If no, please provide the basis for your disagreement, your choice of functional entity, and the rationale for your choice.

Yes

No

11. Information listed in Attachment 3 (Requirement R10): Do you agree that the RAS information required in Attachment 3 provides the Reliability Coordinator with enough detail of each RAS to meet its reliability-related needs? If no, please identify what other reliability-related information should be included in Attachment 3 and the rationale for your choice.

Yes

No

12. Requirement R11: Is there a reliability benefit of Requirement R11? Please provide the rationale

for your answer.

Yes

No

13. Choice of RAS-entity (Requirement R11): Do you agree with the RAS-entity being the entity designated to provide the detailed RAS information to other registered entities with a reliability-related need? If no, please provide the basis for your disagreement, your choice of entity, and the rationale for your choice.

Yes

No

14. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

Responses By Question

1. RAS review and approval (Requirements R1, R2 and R3): Do you agree that RAS should be reviewed and approved by an independent party prior to placing the RAS in-service? If no, please state the basis for your disagreement and an alternative approach.

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Note that Attachment 1, section III Implementation, criterion 2 should be revised slightly as it is too wide and somewhat ambiguous. The devices to be analyzed should be tied to the protection system definition and performance to meet TPL-001-4.

"Documentation showing that any multifunction devised used to perform RAS functions…"

Revise the above to state something like, "Documentation showing that a malfunction of a NERC Protection System component in the RAS does not compromise the ability of the RAS to meet TPL-001-4 and its successors."

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Answer Comment:

While we do not object to the RAS being reviewed and approved by an independent party for new systems, AEP seeks clarity to ensure that existing evaluations on record, performed by the RRO, would be grandfathered.

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

Answer Comment:

We agree that a RAS should be reviewed prior to placing in service. However it is not clear what an independent party is. If that party is the RC (or in our proposal, under Q3 below, the RC or the PC depending on the time frame), then that should be fine. Otherwise, please specify.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6 -

Selected Answer: No

Answer Comment:

Comments: PacifiCorp does not agree that the RAS should be reviewed and approved by an independent party prior to placing the RAS in service. PacifiCorp believes that RAS review should be undertaken by the planning coordinator, the transmission planner and neighboring transmission planners as they are the parties that possess the requisite knowledge to make a determination as to the appropriateness of the RAS.

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - ISO New England, Inc. - 2 - NPCC

Selected Answer: Yes

Answer Comment:

We agree that RAS should be approved prior to service. The R1 approval process should add a period of time that the RAS entity should submit the RAS information prior to the expected in-service date to ensure adequate time for review is provided.

R1. ***At least 180 days*** prior to placing a new or functionally modified RAS in-service, or retiring an existing RAS, each RAS-entity shall submit the information identified in Attachment 1 and Attachment 3 to the reviewing Reliability Coordinator(s). ***At least 30 days prior to placing an RAS in service as part of a CAP, each RAS entity shall submit updated Attachment 1 and Attachment 3 information***. *[Violation Risk Factor:] [Time Horizon:]*

R2 should be modified as follows to include the Attachment 3 information.

R2. For each RAS submitted pursuant to Requirement R1, each reviewing Reliability Coordinator shall, within four full calendar months of receipt of Attachment 1 ***and Attachment 3*** materials, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to the RAS-entity. *[Violation Risk Factor:] [Time Horizon:]*

Document Name:	
Likes:	0
Dislikes:	0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

We suggest that R1 may be adjusted to clarify that the intent is for the data to be submitted to the RC to perform its analysis (per R2) prior to putting the RAS in-service. The current wording is unclear in R1 that the RAS may not be put into service until the approval is received by the RC (per R3).

For example: “R1: Each RAS-entity shall submit the information identified in Attachment 1 to the

reviewing Reliability Coordinator(s) for approval prior to placing a new or functionally modified RAS in-service or retiring an existing RAS.”

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Oncor Electric Delivery - 2 - TRE

Selected Answer: Yes

Answer Comment:

Oncor Electric Delivery believes that it is a good idea to have an independent party review any RAS. However, 90 days for the review seems more reasonable since they are just reviewing the scheme.

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

However, Duke Energy feels that an Independent Third Party is necessary only in the rare occasions when a "conflict of interest" exists among the RAS Entity, PC, TP, or other entity that could be involved in the planning or implementation of a RAS.

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Yes, RAS should be reviewed and approved by the Reliability Coordinator prior to being placed in-service instead of the independent party.

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

But we do not believe this should be the RC. The current NERC Regions (not Regional Entities) have long-standing and effective committee structures that give SPSs thorough technical reviews involving engineering staff from all impacted entities. We would recommend the drafting team allow the use of collaborative forums (in which RCs and PC participate) as a means to perform the analysis and reviews in the standard.

Document Name:

Likes: 0

Dislikes: 0

Eric Senkowicz - Florida Reliability Coordinating Council - NA - Not Applicable - FRCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

An independent party review for an RAS application is inappropriate since an independent party may not understand the complexity of the application without significant investment in time, resources and experience. In addition, an independent party may not understand the required coordination across interconnected systems and may not be as invested in a positive and effective outcome as a potentially impacted party. An alternative approach would be to use a coordinated review by potentially impacted parties including Planning Authorities or

Regional Entities.

Document Name:

Likes: 1 Florida Municipal Power Agency, 3,4,5,6, Gowder Chris

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The Transmission Planner or Planning Coordinator, where RAS impacts multiple Transmission Planners, is the correct function to determine where a RAS Scheme is required. The SDT has not justified why a review step is needed. No other Facility upgrade, installation or protection system addition requires a third party review. There is a planned Protection System Coordination Standard but that is very limited in its coordination. The need for an RAS is determined from TPL studies and planned system performance. The standard can provide the RC with an opportunity to provide opinion, but not approval. There is no need for a third party review.

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

However, Tri-State believes there should be additional language added to acknowledge that Transmission Operators should be allowed to provisionally implement a proposed RAS in cases where there are immediate reliability needs. The standard as currently drafted does not allow for this.

Document Name:

Likes: 0

Dislikes: 0

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We agree with the need to have a higher level reliability authority with a Wide Area view such as Planning Coordinator or Reliability Coordinator. However, we do not understand the emphasis on independence especially when there are FERC standards of conduct and entity level codes of conduct. Furthermore, selecting a Reliability Coordinator or Planning Coordinator will not guarantee this independence anyway as there are still Reliability Coordinators and Planning Coordinators affiliated with equipment owners. Thus, we suggest focusing on the functional entity that should be responsible which we believe is the Planning Coordinator. When entities were registered any issues with independence should have been resolved.

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer:	Yes
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer: No

Answer Comment:

1) Hydro One Networks Inc. agrees with NPCC in that:

Because of its familiarity with its system, it is appropriate for the RC to review a RAS, and requirement R1 identifies the RC as the reviewer. We note that the RC may not be an "independent party" nor does the requirement calls for an "independent party." Conducting a proper review of the RAS's performance and design is more critical than maintaining "independence". An alternative approach is used within NPCC. The PC has the accountability to seek approval for deployment of a new or modified RAS and this process is outlined in NPCC Directory 7, Appendix B. The review is conducted by a group of entities including subject matter experts from RC, TOs, PCs.

Document Name:

Likes: 1 Hydro One Networks, Inc., 1, Farahbakhsh Payam

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: Yes

Answer Comment:

As specified by the SDT, RAS are complex schemes with lots of possible actions that can have a significant impact on BES reliability. It is essential for those schemes to be reviewed by independent entities with expertise in various fields. However, Hydro-Quebec TransEnergie (HQT) thinks that the RC may not always be an independent party as a RAS reviewer. Some RCs have multiple PCs and TOPs within their footprint. Some other RCs perform also TOP functions related to RAS utilization on their BES system.

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Texas RE recommends providing some clarification around what it means to be a RAS-entity and RAS-owner. The Functional Entity referred to as “RAS-entity” should be the “RAS-owner” if there is only a single owner, correct? Who does the designation for the representation? Again, is that assumed to be the owner in a single owner RAS?

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

1) Hydro One Networks Inc. agrees with NPCC in that:

Because of its familiarity with its system, it is appropriate for the RC to review a RAS, and requirement R1 identifies the RC as the reviewer. We note that the RC may not be an “independent party” nor does the requirement calls for an “independent party.” Conducting a proper review of the RAS’s performance *and design is more critical than maintaining “independence”. An alternative approach is used within NPCC. The PC has the accountability to seek approval for deployment of a new or modified RAS and this process is outlined in NPCC Directory 7, Appendix B. The review is conducted by a group of entities including subject matter experts from RC, TOs, PCs.*

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The owner of any protection scheme should be responsible for the correct design and implementation of the scheme – RAS or not. Just like the design of switching to create a blackstart cranking path by a TOP in EOP-005-2, Requirement 6 must be verified by that TOP, the owner of the RAS should be held to the same expectation that the RAS is correctly designed and implemented. If the SDT still believes that some sort of review is required, then that review should be limited in scope to reviewing the generic content of the RAS design and not delve into the technical depth identified in some parts of Attachment 2.

Document Name:

Likes: 0

Dislikes: 0

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer:	Yes
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rico Garcillano - Pacific Gas and Electric Company - NA - Not Applicable - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: No

Answer Comment:

For new or functionally modified RAS's, the standard should be written in a way that ensures the appropriate functional entities are involved in the 1) identification of need for an RAS, 2) initial design and assessment of the RAS, and 3) coordination with other functional entities who may be impacted by operation of the RAS, before a new or functionally modified RAS is placed in-service. There may be some registry situations where all three of these objectives can be accomplished within the same company if no neighboring entities are impacted by the RAS. In such instances, review and approval by an "independent party" should not be a pre-requisite to placing an RAS in-service. We have no objection to involving the appropriate Reliability Coordinator(s) in these pre-requisite steps to RAS implementation.

Document Name:

Likes: 0

Dislikes: 0

2. Information listed in Attachment 1 (Requirement R1): Do you agree that the RAS information required in Attachment 1 is a comprehensive list? If no, please identify what other information you think is necessary for a thorough RAS review.

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:

More detail is needed regarding RAS retirement. The RAS Entity must provide clarity regarding what system conditions would qualify the RAS to be retired/disabled, in order to prevent an RAS from being in service when one is not required.

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

We generally agree with the information required in Attachment 1, but suggest the following changes:

Under Item II, second last bullet: revise “An evaluation indicating that the RAS avoids adverse interactions with other RAS, and protection and control systems.” to “An evaluation demonstration that the RAS settings and operations are properly coordinated with those of other RAS and protection and control systems”.

In addition, we propose that the SDT to add/specify the minimum design criteria as they are needed to achieve both dependability and security. Clear acceptable design criteria should to be included in the standard to allow common RAS design practice across the continent. In the absence of minimum design requirements, it will be difficult for the RC to assess and for the RAS owners to design the appropriate level of redundancy as one of the actions specified in the Attachment 1 requires. Further, it is not clear if “interconnected transmission system” refers to Bulk Electric System as defined by NERC. Please clarify.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Error: Subreport could not be shown.

Selected Answer:	Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: No

Answer Comment:

Documentation showing coordination with other NERC functional entities that may be impacted by the RAS beyond RCs.

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - ISO New England, Inc. - 2 - NPCC

Selected Answer: No

Answer Comment:

The third item in Section II only requires a summary of technical studies be provided. In addition to the summary, the technical studies

	themselves should be provided.
Document Name:	
Likes:	0
Dislikes:	0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer:	Yes
Answer Comment:	
Document Name:	

Likes: 0

Dislikes: 0

Gul Khan - Oncor Electric Delivery - 2 - TRE

Selected Answer: Yes

Answer Comment:

Oncor Electric Delivery believes the list contains more than is necessary for a review and cannot always be obtained for every RAS. In fact, unless the RAS is an existing system during the review period there are usually no schematics to review so I do not believe it is appropriate to request schematic diagrams. The second bullet under General section I asks for “functionality of a new RAS”, which would be a relay functional diagram that depicts how the scheme works and that would be available during the review process.

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

ERCOT supports the SRC comments regarding Attachment 1.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Duke Energy requests further explanation on the removal of the “extreme event” classification.

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eric Senkowicz - Florida Reliability Coordinating Council - NA - Not Applicable - FRCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

From the Attachment 1 introductory paragraph, “When a RAS has been previously reviewed, only the proposed modifications to that RAS require review; however, it will be helpful to the reviewers if the RAS entity provides a summary of the previously approved functionality.” In

	order to effectively review a proposed modification, a reviewer has to understand the original RAS functionality. Suggest changing the wording to "…however, the RAS entity must provide a summary of the previously approved functionality." Requirement R1 and Attachment 1 mandate "Functionality of new RAS or proposed functional modification to existing RAS and documentation of the pre- and post-modified functionality of the RAS" is under I. General, and in Requirement R1 as information that has to be submitted. The wording in the introductory paragraph needs to be revised. In the RAS Retirement Section suggest revising the wording of the second bullet to read: A summary of applicable technical studies and technical justifications needs to be provided upon which the decision to retire the RAS is based. The term "interconnected transmission system" in Section III, bullet 4, is not clear. This is critical as it would affect the redundancy requirement, especially to RAS installed only to mitigate local BES issues. "System", being defined in the NERC Glossary, should be capitalized.
Document Name:	
Likes:	0
Dislikes:	0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: No

Answer Comment:

The 3rd and 4th boxes under "III. Implementation" contain undefined terms, that are unclear, confusing, and duplicative. Tri-State recommends replacing both boxes with:

“Documentation to demonstrate that any single piece of the equipment used to implement the RAS can either be taken out of service or fail, without disabling or compromising the reliability of the RAS.”

Document Name:

Likes: 0

Dislikes: 0

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

While we agree that Attachment 1 includes an exhaustive list of information, we have three concerns with Attachment 1. First, it includes a reference to performance in the TPL-001-4 studies. There is no need to reference the TPL standard anywhere in this standard. TPL should stand alone and will ensure that those performance requirements are met. There have been issues in the past when standards cross-reference other standards. Second, the information required describing the equipment we believe is more detail than is needed to be reviewed by the PC or RC. The PC and RC simply need the information such as the potential actions and associated contingencies and any failure modes (e.g. RAS partially operates) which could include an expanded list of contingencies to study along with RAS actions. They do not need to be familiar with the actual equipment to perform this review. Third, we do not believe it should be the RAS-entity (i.e. equipment owner) that submits the evaluation of interactions with other RAS. Rather, we believe this is the PC's responsibility and the PC should already have studied and approved the RAS at this juncture.

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer: No

Answer Comment:

Requirement R1 currently requires the 'RAS-entity' to provide the documentation in Attachment 1. The 'RAS-entity' term is a very generic term as either the RAS-Owner or RAS-Planner could be identified as a 'RAS-entity'. The standard should be more specific as to who should provide the information in Attachment 1. The RAS-Owner can only provide the information in Section I and Section III in Attachment 1. Section II should be specific to the Transmission Planner/RAS-Planner as the RAS-Owner

(Transmission Owner) does not have all the tools and information to perform and provide the studies/documentation for this section.

2) Attachment 1 is specific to identifying which documentation should be provided by a RAS-entity. In the Implementation (Section III) requirements, there is a requirement that states documentation must be provided to show “that an appropriate level of redundancy is provided…” If there is a requirement to provide redundancy, it should be a separate requirement, explicitly stated, and not reside in an Attachment outside of Requirement R1, where this crucial detail could easily be missed.

3) The statement, “the RC may request additional information on any reliability issue related to the RAS” should be moved from Attachment 2 to Attachment 1.

4) The checklist particularly that in Attachment 1 should be shortened and/or replaced by a simpler list. The reviewer (RC) may further decide on the details.

5) Hydro One Networks Inc. agrees with NPCC on the following:

The term “Interconnected Transmission System” in Section iii, bullet 4, is not clear. This is critical as it would affect the redundancy requirement, especially to RAS installed only to mitigate local BES issues.

The list in Attachment 1 should explicitly include arming requirement and how it is achieved.

The Drafting team could consult NPCC Directory 7 including Appendix B for a comprehensive list of parameters that are reviewed for new/modified RAS.

Document Name:

Likes: 1 Hydro One Networks, Inc., 1, Farahbakhsh Payam

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: Yes

Answer Comment:

HQT agrees with the information required in Attachment 1 for review purpose, with the following comments:

- Please clarify what is expected for “single component failure”. We believe it should include only duplication of electrical components. Please indicate that physical separation is not intended (such as a tower carrying two communication links).

- Part II, 5th paragraph: the reference to TPL and to performance requirements is not clear. We propose the following modification - “… satisfies the voltage, frequency and stability performance requirements of Table 1 of NERC Reliability Standard TPL-001-4 or its successor.” If the intent of referring to P7 contingencies is the allowance for non-

	consequential and firm load loss, this should be stated more explicitly in the standard. - Part III, 4th paragraph: please indicate clearly that this requirement applies only to RAS needed to respect System performance under TPL-001-4 contingencies, and not for all other RAS. There is some confusion as to which RAS does this requirement apply to. Attachment 1 refers to TPL-001-4, but not the guidelines for Attachment 1, neither does Attachment 2. Does this apply only to RAS installed to meet TPL? This is how HQT interprets the current language. What about the RAS installed to meet other NERC standards (FAC, TOP, ...) ? Clarification is needed in the language used for this requirement. Depending on the interpretation, the current language may read as if redundancy would be required for RAS installed to meet regional requirements beyond NERC TPL.
Document Name:	
Likes:	0
Dislikes:	0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:	Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE is concerned that the UVLS standards will not capture UVLS as UVLS program in the ERCOT interconnection and that the RAS definition does not cover UVLS. Additionally, this standard only mentions new or modified RAS and does not account for the fact that RAS could be in place right now. Texas RE recommends clarify regarding “reliability related need” as this statement is vague and could lead to multiple interpretations.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

Hydro One Networks Inc.:

1) Requirement R1 currently requires the ‘RAS-entity’ to provide the documentation in Attachment 1. The ‘RAS-entity’ term is a very generic term as either the RAS-Owner or RAS-Planner could be identified as a ‘RAS-entity’. The standard should be more specific as to who should provide the information in Attachment 1. The RAS-Owner can only provide the information in Section I and Section III in Attachment 1. Section II should be specific to the Transmission Planner/RAS-Planner as the RAS-Owner (Transmission Owner) does not have all the tools and information to perform and provide the studies/documentation for

this section.

2) Attachment 1 is specific to identifying which documentation should be provided by a RAS-entity. In the Implementation (Section III) requirements, there is a requirement that states documentation must be provided to show “that an appropriate level of redundancy is provided…” If there is a requirement to provide redundancy, it should be a separate requirement, explicitly stated, and not reside in an Attachment outside of Requirement R1, where this crucial detail could easily be missed.

3) The statement, “the RC may request additional information on any reliability issue related to the RAS” should be moved from Attachment 2 to Attachment 1.

4) The checklist particularly that in Attachment 1 should be shortened and/or replaced by a simpler list. The reviewer (RC) may further decide on the details.

5) Hydro One Networks Inc. agrees with NPCC on the following:

The term “Interconnected Transmission System” in Section iii, bullet 4, is not clear. This is critical as it would affect the redundancy requirement, especially to RAS installed only to mitigate local BES issues.

The list in Attachment 1 should explicitly include arming requirement and how it is achieved.

The Drafting team could consult NPCC Directory 7 including Appendix B for a comprehensive list of parameters that are reviewed for new/modified RAS.

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

We generally agree with the information required in Attachment 1, but suggest the following changes:

Under Item II, second last bullet: revise "An evaluation indicating that the RAS avoids adverse interactions with other RAS, and protection and control systems." to "An evaluation demonstration that the RAS settings and operations are properly coordinated with those of other RAS and protection and control systems".

The SRC recommends that Requirement R2 be clarified to indicate that the four month time period for RAS evaluations commences when all information required by Attachment 1 is received. The following clarification is suggested:

"For each RAS submitted pursuant to Requirement R1, each reviewing Reliability Coordinator shall, within four full calendar months of receipt of all information required to be provided to the Reliability Coordinator in Attachment 1, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to the RAS-entity…"

Document Name:

Likes:	0
Dislikes:	0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer:	Yes
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rico Garcillano - Pacific Gas and Electric Company - NA - Not Applicable - WECC

Selected Answer: Yes

Answer Comment:

- Should the first item in the Implementation Section clarify the minimum level of control & monitoring to achieve adequate situational awareness for the scheme?

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: No

Answer Comment:

Requirement R4 requires the Transmission Planner to perform a periodic evaluation of each RAS within its planning area at least once every 60 calendar months. Attachment 1, section II, implies that the Transmission Planner is involved in performing studies of each new or functionally modified RAS before it is placed in service. We recommend the SDT consider modifying Requirement R4 to clarify the Transmission Planner's role in studying new or functionally modified RAS's on an as needed basis in support of an RAS-entity's need to meet Requirement R1; or add a new requirement for the Transmission Planner that addresses this pre-installation/modification role.

The submitting RAS-entity should also identify the TOP(s) and GOP(s) that have been coordinated with during design of the RAS. We recommend adding a check box prior to the last one in section II that reads - “Identification of affected TOPs and/or GOPs”.

Document Name:

Likes: 0

Dislikes: 0

3. Choice of Reliability Coordinator (Requirements R1, R2 and R3): Do you agree with the Reliability Coordinator being the functional entity designated to review the RAS? If no, please provide the basis for your disagreement, your choice of functional entity to conduct the reviews, and the rationale for your choice.

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We would prefer that R2 (review the RAS) apply to the RCs **and** the PCs that could be affected by the RAS. However, if the SDT wants R2 to apply to only one functional entity, then we accept the choice of the RC, but suggest wording like, “each reviewing Reliability Coordinator, in conjunction with applicable Planning Coordinators, shall . . . “ to obligate the RC to obtain input from the PCs on the planning horizon impacts of the RAS. RCs should be obligated to obtain input from applicable PCs because they do not have the same knowledge and capabilities of PCs to review the planning horizon impacts of a RAS.

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Answer Comment:

AEP supports the choice of the RC to perform the review, however we are concerned that the RC may not be far enough removed from the RAS implementation process to be considered completely impartial. In addition, they may not possess the necessary expertise to adequately or thoroughly review the RAS systems in the established time frame (4 months).

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

We do not see how the RC alone should be responsible for, or in some cases capable of, fully evaluate the impacts of RASs. We see the need to also involve the Planning Coordinator for assessing the

At present, the regions (primarily the RRO) have task forces or groups made up of both operating and planning people from their members to conduct this evaluation. The regions provide a thorough review of RASs that are proposed by Asset Owners and Transmission Planners. We do not see how either the RC or PC can provide this review in kind; in other words, neither can fill in the blank vacated by the established regional tasks forces or groups. Further, both have compliance responsibilities: an RC must ensure the RAS meets its operating standards requirements (less than a year; daily, weekly) and a PC must ensure the RAS meets its planning standards requirements (greater than a year). We therefore suggest the SDT to consider splitting the evaluating requirements into the long-term planning timeframe (assigned to the PC) and operations planning timeframe (assigned to the RC).

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment:

ATC would prefer that R2 (review the RAS) apply to the RCs and the PCs that could be affected by the RAS. However, if the SDT prefers R2 to apply to only one functional entity, then ATC accepts the choice be the RC, but recommends wording like, "each reviewing Reliability Coordinator, in conjunction with applicable Planning Coordinators, shall . . . " to obligate the RC to obtain input from the PCs on the planning horizon impacts of the RAS. RCs should be obligated to obtain input from applicable PCs because RCs do not have the same knowledge and capabilities of PCs to review the planning horizon impacts of a RAS.

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Dominion believes that RAS should be reviewed and approved in both the planning and operating horizons by designated entities within whose area(s) the Facility (ies) the RAS is designed to protect reside. Dominion could have supported the recommendation contained in the SCPS Technical designating the RC and the PC, but a review of the most recent NCR Active Entities List indicates no entity is registered as PC. For this reason, we chose to recommend the TP instead of the PC.

Document Name:

Likes: 0

Dislikes: 0

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6 -

Selected Answer: Yes

Answer Comment:

Comments: PacifiCorp does not agree with the RC being the functional entity designated to review the RAS. PacifiCorp believes that RAS review should be undertaken by the planning coordinator, the transmission planner and neighboring transmission planners as they are the parties that possess the requisite knowledge to make a determination as to the appropriateness of the RAS.

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - ISO New England, Inc. - 2 - NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

The RC should also include the Planning Coordinator in the review of the RAS. The RC does not possess adequate capabilities to review the RAS in the Planning Horizon.

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Oncor Electric Delivery - 2 - TRE

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Answer Comment:

ERCOT is concerned that the placement of responsibility to evaluate the impacts of RASs on the RC alone may ignore current, effective processes as well as the current responsibilities of the Planning Coordinator. Thus, ERCOT respectfully suggests that the SDT assess the effectiveness of the current processes and evaluate how such can be incorporated into the proposed Standard. In the alternative, the SDT should evaluate the need to involve the Planning Coordinator in the evaluation of the impacts of RASs. More specifically, at present, the regions (primarily the RRO) have task forces or groups made up of both operating and planning personnel from their members to conduct evaluations of proposed and modified RASs. Through these task forces or groups, a thorough review of RASs that are proposed by Asset Owners and Transmission Planners is performed. As current processes involve both real-time operations and planning function personnel, it is unlikely that either entity in isolation can fill in the gap that would be created once the established regional tasks forces or groups vacate their responsibilities under the RRO. Further, both the RC and the PC have existing compliance responsibilities associated with RASs: an RC must ensure the RAS meets its operating standards requirements (less than a year; daily, weekly) and a PC must ensure the RAS meets its planning standards requirements (greater than a year). ERCOT, therefore, suggests that, in the event that current processes cannot be relied upon or incorporated into the proposed standard, the SDT, at a minimum, consider revising the requirements to ensure that any RAS evaluations performed by the RC are done in coordination with the PC such that evaluations that are performed account for both the long-term planning timeframe and operations planning timeframe.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer:	Yes

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer:	Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: No

Answer Comment:

RCs need to be aware of all SPSs in their footprint and would be a logical entity to take over the RRO's responsibility for maintenance of a SPS database. However given the wide-area impacts of RAS, the technical reviews and verification of proper operation should be done in a collaborative forum.

Document Name:

Likes: 0

Dislikes: 0

Eric Senkowicz - Florida Reliability Coordinating Council - NA - Not Applicable - FRCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The type of review envisioned by these standard requirements are significantly and inappropriately broader than the responsibilities and functions of the Reliability Coordinator as laid out in the NERC Functional Model. In addition to conflicting with the functional model, the tools, breadth of study and coordination envisioned by these requirements would require many of the Reliability Coordinators to acquire new tools, study capabilities and resources to achieve the desired reviews. Finally, these new responsibilities for the RCs would become duplicative with the current, and appropriate practice of studying RAS installation and effectiveness in a Regionally coordinated manner across the Planning Horizons. Subject matter expertise for the type of studies needed to evaluate RASs resides in the planning tools and horizon as the issues that require RASs are usually identified in the planning horizon. Regional Entities could perform the “independent” reviews as they have the expertise being used today to perform the reliability assessments of each Region.

Document Name:

Likes:	1	Florida Municipal Power Agency, 3,4,5,6, Gowder Chris
Dislikes:	0	

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer:	No

Answer Comment:

The NERC Functional Model defines the RC as being “The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.” It is not responsible for the planning or installation of a Protection System. The NERC Functional Model does not support the RC as being the reviewer. The RC does not review nor have the approval authority over any other facility or protection system installation.

A RAS needs to be categorized based on impact to facilitate who approves. A RAS that impacts one Transmission Planner only would be coordinated and approved by that Transmission Planner. A RAS that impacts multiple Transmission Planners would be referred to the Planning Coordinator that the Transmission Planners report to in the functional model. Where multiple Planning Coordinators are impacted, then suggest following the PRC-006 (UFLS) approach and require coordination of studies.

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Since approval of the installation of a RAS involves performing planning studies, we believe the Planning Coordinator should be the entity responsible for reviewing and approving RAS. We certainly agree the RC should be made aware of new RAS but believe they do not have the responsibility to approve the RAS since they are the operating entity. We view this no different than planning a new transmission line and associated Protection Systems which are performed by the Planning Coordinator.

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Error: Subreport could not be shown.

Selected Answer:	Yes

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer: No

Answer Comment:

Hydro One Networks Inc.:

1) The majority, if not all, the supporting documentation required in Attachment 1 is based on NERC standards PRC-012-0/1, PRC-013 and PRC-014. These standards were all ONLY applicable to the Regional Reliability Organization (RRO). RRO

organizations already have established programs, standards, directories and procedures in place that request this information from RAS-entities. RRO is the most experienced in performing reviews of the requested documentation and this system has already been in place for years. The RRO should be functional entity designated to review the RAS.

2) The SDT has suggested that the RC has the option of having another entity (e.g. Regional Entity) review the RAS. This should be reflected in R2.

Document Name:

Likes: 1 Hydro One Networks, Inc., 1, Farahbakhsh Payam

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: Yes

Answer Comment:

Although HQT understands the SDT's motivation for suggesting a NERC functional entity instead of the RRO for the review requirements, HQT disagrees that the RC meets the criteria for a third-party independent review with expertise in planning, operation, protection, etc. No single NERC functional entity is adequate for performing the review by itself. The existing RROs' processes (NPCC, WECC, …) definitely meet the criteria for a thorough and rigorous review with multiple RCs, TPs, TOPs and much wider and independent field of expertise than a single RC.

Since there seems to be an opening within the standard (R2 rationale) to allow the RC to delegate this task to a third-party (e.g. the RROs current process), HQT would support this approach. However, it seems like going through the RC to obtain a review by the RRO is somewhat "fill in the blank" and administrative with no improvement in reliability.

Because of the importance of reliability for RROs and the existing process for RAS review, the SDT should consider keeping the requirements for submitting a RAS for review (R1) assigned to the RAS entity, and simply state that the submission for review should be made to the RRO. In this case, R1 and R3 would still be applicable to the RAS-entity for the submittal for review by and approval by the RRO prior to placing RAS in service. The current R2 applicable to the RC could be removed.

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Texas RE is concerned with how the information to evaluate RAS will be provided to the Transmission Planner or Planning Coordinator.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

Hydro One Networks Inc.:

1) The majority, if not all, the supporting documentation required in Attachment 1 is based on NERC standards PRC-012-0/1, PRC-013 and PRC-014. These standards were all ONLY applicable to the Regional Reliability Organization (RRO). RRO

organizations already have established programs, standards, directories and procedures in place that request this information from RAS-entities. RRO is the most experienced in performing reviews of the requested documentation and this system has already been in place for years. The RRO should be functional entity designated to review the RAS.

2) The SDT has suggested that the RC has the option of having another entity (e.g. Regional Entity) review the RAS. This should be reflected in R2.

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Using the criteria outline by the SDT in its recent webinar, in addition to the independence of the reviewer and geographic span, the team also mentioned “expertise in planning, protection, operations, equipment”. The attributes of this expertise to the level expected do not currently exist in most RC organizations. RC’s are primarily operating entities (and even then primarily in real-time) and not experts in planning (beyond the operating time frame), protection or equipment. Transmission Owners, Transmission Operators and Transmission Planners normally have that expertise. The FERC acknowledged the limited RC technical expertise in evaluating details of restoration plans in its Order 749, Paragraph 38 (“…basis on which a reliability coordinator rejects a restoration plan will necessarily be based on generic engineering criteria…”). The review of a RAS by an RC should not be held to a higher expectation due to similar limited expertise with the equipment and systems involved in a RAS.

The “flexibility” for the RC granted in the requirement to designate a third party would seem to immediately invalidate the original assumptions that the RC has the compelling capability to adequately perform the review while meeting the SDT’s characteristics of the reviewing entity. To allow this, while still requiring the RC to be responsible for the review, seems like an improper administrative burden and a potential compliance risk that the RC may assume because it had to find an entity more qualified than itself to perform the review. If an RC is not qualified to review all of the items in Attachment 2 then how can it be held responsible for the results of the review?

Regarding the designation of a third party reviewer, clarification needs to be made regarding what it means to “retain the responsibility for compliance.” Does this simply mean that the review takes place or that there is some implied resulting responsibility for the correct design and implementation that the RC is now accountable for.

Finally, also regarding the designation of a third party reviewer, is the term “third party” meant to be any entity not involved in the planning or implementation of the RAS?

The alterative to using the RC? Although there appears to be a movement to remove the RRO as a responsible entity from all standards, those organizations through their membership expertise and committee structures more closely match the characteristics stated by the SDT – expertise in planning/protection/operations/equipment, independence by virtue of the diversity of its members, wide area perspective, and continuity. If for some reason the SDT, believes that the RRO still should not be involved then an alternative could be the Planning Coordinator function which should have similar expertise to the Transmission Planners that are to specify/design a RAS per the functional model yet would have some independence which the SDT is looking for.

Document Name:	
Likes:	0
Dislikes:	0

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We do not see how the RC alone should be responsible for, or in some cases capable of, fully evaluating the impacts of RASs. We see the need to also involve the Planning Coordinator for assessing the RAS. At present, the regions (primarily the RRO) have task forces or groups made up of both operating and planning people from their members to conduct this evaluation. The regions provide a thorough review of RASs that are proposed by Asset Owners and Transmission Planners. These processes should be retained and the proposed requirements should not preclude these to continue.

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rico Garcillano - Pacific Gas and Electric Company - NA - Not Applicable - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

4. Checklist in Attachment 2 (Requirement R2): Do you agree that the checklist in Attachment 2 provides a comprehensive guide for the Reliability Coordinator to facilitate a thorough RAS review? If no, please identify what other reliability-related considerations should be included in Attachment 2 and the rationale for your choice.

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

The paragraph, “RAS retirement reviews may use an abbreviated format that concentrates on the Planning justifications describing why the RAS is no longer needed. Implementation issues will seldom require removal review” is confusing. Consider the following wording, “may be shorter and simpler. Few, if any, of the Design and Implementation checklist items will apply to a RAS retirement review. A retirement review should primarily assure that there is adequate

Planning justifications regarding why the RAS is no longer needed."

We suggest that R4 return to the 5-year requirement versus the 60 full calendar month. There is no additional reliability benefit to specifying 60 months versus once at least every 5 calendar years. However, there is a scheduling benefit to once at least every 5 calendar years. The 5 calendar year option allow for flexibility with no reduction in reliability. It is reasonable for any requirement spanning two or more years to use "annual calendar years". For requirements that are less than two years, calendar month(s) is more appropriate.

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

Answer Comment:

We generally agree with the proposed guideline presented in Attachment 2, but have difficulty understanding the first bullet which reads: “frequency-related instability” In fact, if we apply our interpretation correctly that it means instability caused by frequency excursion or collapse or generator instability, then this term will eliminate the possibility of instability caused by voltage collapse. We suggest to replace this term with “system instability” which should cover all instability cases.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

However, in Attachment 2, the paragraph, “RAS retirement reviews may use an abbreviated format that concentrates on the Planning justifications describing why the RAS is no longer needed. Implementation issues will seldom require removal review” is confusing. For clarity, ATC recommends rewording, such as “may be shorter and simpler. Few, if any, of the Design and Implementation checklist items will apply to a RAS retirement review. A retirement review should primarily assure that there is adequate Planning justifications regarding why the RAS is no longer needed.”

Document Name:

Likes:	0
Dislikes:	0

Brian Bartos - CPS Energy - 3 -

Selected Answer:	Yes
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Dominion believes “frequency-related instability” is not a universally defined/accepted term. Instead, consider referencing specifically PRC-006 attachment 1 or 1A.

Document Name:

Likes: 0

Dislikes: 0

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6 -

Selected Answer:	Yes
Answer Comment:	Requirement R4 mandates the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, as well as the BES performance following an inadvertent operation of the RAS. The drafting team considered the RAS classification systems used by several Regions to be rooted in PRC-012, Requirement R1, R1.4. which reads: *“Requirements to demonstrate 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.”* Although, the drafting team is not proposing to use formal RAS classifications, the intent of PRC-012, Requirement R1, R1.4. is retained in Requirement 4 and Attachment 1.
Document Name:	
Likes:	0
Dislikes:	0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: No

Answer Comment:

Standards are meant to be clear and defined. However, this checklist introduces ambiguity. There are implications of redundancy, but more clarity is needed. Further, the level of review required by the RC is too subjective. What distinguishes "significant" from "lesser impact?"

The second-to-last bullet in the Design section should be clarified because it's difficult to understand.

The last bullet in the Design section should be deleted because future system planning is the TP/PC function and not an RC function.

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Requirement R4 mandates the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, as well as the BES performance following an inadvertent operation of the RAS.

The drafting team considered the RAS classification systems used by several Regions to be rooted in PRC-012, Requirement R1, R1.4. which reads: *"Requirements to demonstrate 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."* Although, the drafting team is not proposing to use formal RAS classifications, the intent of PRC-012, Requirement R1, R1.4. is retained in Requirement 4 and Attachment 1.

Questions 5 and 6 pertain to these topics.

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - ISO New England, Inc. - 2 - NPCC

Selected Answer: Yes

Answer Comment:

Requirement R4 mandates the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, as well as the BES performance following an inadvertent operation of the RAS.

The drafting team considered the RAS classification systems used by several Regions to be rooted in PRC-012, Requirement R1, R1.4. which reads: *"Requirements to demonstrate 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."* Although, the drafting team is not proposing to use formal RAS classifications, the intent of PRC-012, Requirement R1, R1.4. is retained in Requirement 4 and Attachment 1.

Questions 5 and 6 pertain to these topics.

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Oncor Electric Delivery - 2 - TRE

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

While ERCOT is not opposed to a guideline regarding the performance of RAS evaluations, Attachment 2 is overly prescriptive and does not allow for RCs to utilize their operational experience and engineering judgment. ERCOT recommends that the introductory paragraph to Attachment 2 be revised to provide greater flexibility regarding RAS evaluations. The following revisions are suggested:

The following checklist provides reliability related considerations for the Reliability Coordinator to consider for inclusion in its evaluation for each new or functionally modified2 RAS. The RC should utilize the checklist to determine those considerations that are applicable to the RAS evaluation being performed; however, RAS evaluations are not limited to the checklist items and the RC may request additional information on any reliability issue related to the RAS

ERCOT also supports the SRC comments regarding Requirement R2.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

See Duke Energy's attachment for suggested revisions to Attachment 2.

Document Name: PRC-012-2_AHM_Attachment 2 RC RAS Review Checklist_WTL_JSW_edits_18MAY2015.docx

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer: Yes

Answer Comment:

Requirement R4 mandates the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, as well as the BES performance following an inadvertent operation of the RAS.

The drafting team considered the RAS classification systems used by several Regions to be rooted in PRC-012, Requirement R1, R1.4. which reads: *“Requirements to demonstrate 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.”* Although, the drafting team is not proposing to use formal RAS classifications, the intent of PRC-012, Requirement R1, R1.4. is retained in Requirement 4 and Attachment 1.

Questions 5 and 6 pertain to these topics.

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: No

Answer Comment:

We agree that the list is a comprehensive guide, but do not believe this should be done solely by the RC.

Document Name:

Likes: 0

Dislikes: 0

Eric Senkowicz - Florida Reliability Coordinating Council - NA - Not Applicable - FRCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

See comment to number 3 that disagrees with the RC being the appropriate reviewer.

Document Name:

Likes: 1 Florida Municipal Power Agency, 3,4,5,6, Gowder Chris

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

In the Determination of Review Level, the three conditions listed can occur at any time for the failure of a RAS to operate or operate inadvertently, thereby mandating that the entire checklist be followed.

Attachment 2 states that the level of review may be limited if the system response for failure of the RAS to operate or inadvertent operation of the RAS does not result in certain significant conditions.

However, Attachment 2 does not explicitly describe what portions of Attachment 2 would be considered a limited review. It only states that if certain operating conditions are possible as the result of the failure to operate or inadvertent operation then the entire Attachment 2 checklist should be followed.

It must be recognized that the conditions in Attachment 2 are too broad for determining whether a full-scale or limited review is required. Specifically, the standard should quantify the load in the condition “unplanned tripping of load or generation.” This condition captures tripping of ultimately even very small generators and loads, i.e. the anticipated impact does not correlate with the required depth of the review. It is suggested to consider modification of this particular condition.

Elimination of Attachment 2 should be considered. The Planning Entity and Transmission Owner has the expertise per the Functional Model to develop a RAS.

Requirement R4 mandates the Transmission Planner perform a technical evaluation (planning analysis) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, as well as the BES performance following an inadvertent operation of the RAS.

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: No

Answer Comment:

Tri-State recommends changing the “Determination of Review Level” section to read:

“The RC is allowed some latitude in the depth of their review based on the individual Remedial Action Scheme’s complexity and implications. Nevertheless, the RC shall follow the entire checklist should the RAS:

- *Impact the ability of the BES to operate within established IROLs*
- *Contribute to or have the potential to cause wide-area:*
    - *cascading of transmission facilities;*
    - *uncontrolled separation;*
    - *voltage instability; or*
    - *frequency instability. “*

Document Name:

Likes: 0

Dislikes: 0

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

We agree Attachment 2 represents a comprehensive list of information for a higher level reliability authority to review. However, we believe the PC should be performing the review.

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Answer Comment:

We request to add “pursuant to Requirement R2” after ‘review’ in the opening paragraph so that it reads “The following checklist identifies important reliability related considerations for the Reliability Coordinator to review pursuant to Requirement R2 and verify for each new or functionally modified RAS.” This matches the Attachment 1 wording.

Document Name:		
Likes:	0	
Dislikes:	0	

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:

Answer Comment:

Document Name:		
Likes:	1	Hydro One Networks, Inc., 1, Farahbakhsh Payam

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment:

Attachment 2 seems redundant with Attachment 1. The SDT should consider merging them together and referring to a single attachment for the key items to submit for review and review checklist of those items.

The section “Determination of Review Level” needs some clarification. What is a “limited review”? What items from the checklist can be skipped in this case? At a minimum, some guidelines should be added.

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE is concerned that UVLS will not be considered. Project 2008-02.2 UVLS indicates in the technical guide that certain UVLS will not be in a UVLS Program but would be considered a RAS but it does not appear that UVLS is considered part of RAS. The entire checklist should be used for voltage-related instability.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Requirement R4 mandates the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, as well as the BES performance following an inadvertent operation of the RAS.

The drafting team considered the RAS classification systems used by several Regions to be rooted in PRC-012, Requirement R1, R1.4. which reads: *"Requirements to demonstrate 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.”* Although, the drafting team is not proposing to use formal RAS classifications, the intent of PRC-012, Requirement R1, R1.4. is retained in Requirement 4 and Attachment 1.

Document Name:

Likes: 0

Dislikes: 0

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Error: Subreport could not be shown.

Selected Answer:	Yes

Answer Comment:

We generally agree with the proposed guideline presented in Attachment 2, but have difficulty understanding the first bullet which reads: "frequency-related instability" In fact, if we apply our interpretation correctly that it means instability caused by frequency excursion or collapse or generator instability, then this term will eliminate the possibility of instability caused by voltage collapse. We suggest to replace this term with "system instability" which should cover all instability cases.

Requirement R4 mandates the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, as well as the BES performance following an inadvertent operation of the RAS.

The drafting team considered the RAS classification systems used by several Regions to be rooted in PRC-012, Requirement R1, R1.4. which reads: *“Requirements to demonstrate 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.”* Although, the drafting team is not proposing to use formal RAS classifications, the intent of PRC-012, Requirement R1, R1.4. is retained in Requirement 4 and Attachment 1.

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

BPA requests clarification of Attachment 2 Reliability Coordinator RAS Review Checklist, Implementation, bullet six: RAS automatic arming, if applicable, has the same degree of redundancy as the RAS. What is meant by "the same degree of redundancy"?

Document Name:

Likes: 0

Dislikes: 0

Rico Garcillano - Pacific Gas and Electric Company - NA - Not Applicable - WECC

Selected Answer: Yes

Answer Comment:

By definition though, any RAS that is designed to trip load or generation would require a full review since an "inadvertant operation of the RAS" **WOULD** result in unplanned tripping of load or generation. What then would constitute a scheme that could be reviewed to a lesser degree?

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

5. Choice of Transmission Planner (Requirement R4): The Transmission Planner is required to perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, as well as the BES performance following an inadvertent operation of the RAS. Do you agree with the Transmission Planner being the functional

entity designated to evaluate the RAS? If no, please provide the basis for your disagreement, your choice of functional entity to conduct the evaluations, and the rationale for your choice.

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We suggest that R4 (evaluate the RAS) require the TP to obtain input from affected TOPs and RAS-owners as part of the RAS evaluation with wording like, “Each Transmission Planner, in conjunction with affected Transmission Operators and the RAS-owner, shall . . .“ Affected TOPs have knowledge and capabilities to assess the operating horizon impacts of a RAS that TPs do not have. In the same vain, RAS-owners have more knowledge of the design and purpose of the RAS that TPs.

We suggest changing the word “applicable” to “affected” in the comment above to clarify only “affected” TOP’s and RAS owners need to submit input or participate in the review.

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

At present, many Transmission Owners are also registered as the Transmission Planners (for the assets that the TOs own). A proper evaluation of the RAS should be performed by an entity that is either not also the TP or has a wider perspective than the TP. We believe a PC is more suitable to perform this task than the TP, and therefore suggest replacing the TP with the PC.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment:

ATC recommends that R4 (evaluate the RAS) require the TP to obtain input from affected TOPs and RAS-owners as part of the RAS evaluation and reword as follows: “Each Transmission Planner, in conjunction with affected Transmission Operators and the RAS-owner, shall . . . “. Affected TOPs have knowledge and capabilities to assess the operating horizon impacts of a RAS that TPs do not have. In the same vain, RAS-owners have more knowledge of the design and purpose of the RAS that TPs.

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Dominion believes that RAS should be reviewed and approved by both, the RC and the TP within whose area(s) the Facility (ies) the RAS is designed to protect reside.

Document Name:

Likes: 0

Dislikes: 0

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: No

Answer Comment:

Why does the RC perform the initial review and then the TP performs subsequent reviews? This does not follow the philosophy of an independent reviewer.

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - ISO New England, Inc. - 2 - NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Oncor Electric Delivery - 2 - TRE

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Answer Comment:

At present, many Transmission Owners are also registered as the Transmission Planners (for the assets that the TOs own). Although it is clear that such an entity would have greater expertise regarding the function of the RAS, such evaluations should also be coordinated with and reviewed by the applicable PC. Such coordination and review would allow PCs to ensure that the assessment of the impact of RASs accounts for the broader system perspective and characteristics. ERCOT recommends that the Requirement R4 be modified to ensure that assessments performed by the Transmission Planner are coordinated with or reviewed by the applicable PC.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eric Senkowicz - Florida Reliability Coordinating Council - NA - Not Applicable - FRCC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Yes – however the Planning Authority should be involved in the evaluation as they are better positioned to study, identify and coordinate potential impacts on areas where multiple TPs are involved or potentially impacted.

Document Name:

Likes: 1 Florida Municipal Power Agency, 3,4,5,6, Gowder Chris

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

In Requirement R4, the draft standard establishes Transmission Planners as being responsible for performing evaluations of each RAS in its planning area. However, a mechanism/requirement for providing the TP with the required information from the Reliability Coordinator is not defined. Suggest rewording R4 to:

R4. Each Transmission Planner shall perform an evaluation of information provided by the Reliability Coordinator for each RAS within its planning area at…

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We disagree with the TP being the entity responsible to evaluate the RAS. Final review and approval should be the responsibility of the highest level planning authority which is the Planning Coordinator. This is consistent with the functional model. In those areas, where there is not a Planning Coordinator, the Transmission Planner could be substituted and actually represents the reality that the Transmission Planner is really serving as the Planning Coordinator anyway.

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 1 Hydro One Networks, Inc., 1, Farahbakhsh Payam

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE recommends adding clarity for submitting data to the Transmission Planner, as there is no specific requirement to do so. R11 states that if an entity receives a request with a “reliability related need” the RAS-entity shall provide the information. Texas RE recommends adding clarity to “reliability related need”.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1 - TRE

Selected Answer: No

Answer Comment:

For the ERCOT Interconnection, CenterPoint Energy believes the PC should be the designated functional entity to evaluate the RAS as described in Requirement R4 in the preliminary draft of PRC-012-2. ERCOT ISO presently performs this function and is best positioned to see the wide-area view in the ERCOT planning area. The established regional rules detail ERCOT ISO's evaluation which is performed at least every 60 months, as Requirement R4 is currently drafted. Section 11.2 'Special Protection System' of the ERCOT Nodal Operating Guides is attached for reference.

CenterPoint Energy suggests the following options to address evaluation of the RAS within the ERCOT Interconnection:

1. Change Transmission Planner to Planning Coordinator in Requirement R4. (preferred option)
2. Add "Planning Coordinator – ERCOT Interconnection" in the Applicability section and revise the beginning of Requirement R4 to state "Each Transmission Planner or Planning Coordinator shall perform an evaluation…."
3. Add a regional variance in PRC-012-2 for the ERCOT Interconnection.

Document Name: Section 11.2_Special Protection System_ERCOT Nodal Operating Guides_20140401.docx

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

At present, many Transmission Owners are also registered as the Transmission Planners (for the assets that the TOs own). A proper evaluation of the RAS should be performed by an entity that is either not also the TP or has a wider perspective than the TP. We believe a PC is more suitable to perform this task than the TP, and therefore suggest replacing the TP with the PC.

Note - These SRC comments represent a consensus of the ISOs/RTOs with the exception of ERCOT.

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rico Garcillano - Pacific Gas and Electric Company - NA - Not Applicable - WECC

Selected Answer: Yes

Answer Comment:

Is the expectation that the Transmission Planner fill out (update) Attachment 1 as part of it's review? As Attachement 1 is currently written, it appears that Attachment 1 is only filled out for new or functionally modified schemes. I can see that new or modified schemes are designed to avoid the single component failure, however "grandfathered" schemes that are still needed and still effective as is could be missed.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

6. No RAS Classification (Requirement R4): The drafting team considered the RAS classification systems used by several Regions to be rooted in PRC-012, Requirement R1, R1.4. which reads: "Requirements to demonstrate 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." Although, the drafting team is not proposing to use formal RAS classifications, the intent of PRC-012, Requirement R1, R1.4. is retained in Requirement 4 and Attachment 1. Do you agree that the language of Requirement R4, its Parts, and Attachment 1 accomplish the objectives of RAS "classification" without having a formal RAS classification system in the standard? If no, please provide the basis for your disagreement and describe an alternate proposal.

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:	Yes
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We agree that the parts of R4 include reasonable aspects of the RAS to evaluate, but the RAS “classification” should be based on the RAS definition. For R4.3, we propose replacing “satisfies the requirements of Category P7 in Table 1 of NERC Reliability Standard TPL-001-4, or its successor” with “is allowed to result in an interruption of firm Transmission Service or Non-Consequential Load Loss”. This wording is simpler and more straightforward and would not be subject to change if a successor of TPL-001-4 does not a Category P7, changes the Category P7 contingency, or changes the associated performance requirements.

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

In the absence of the classification and minimum design requirements there will be risks for some RAS to be under or overdesigned subject to personal interpretation of the standard.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment:

ATC agrees that the parts of R4 includes reasonable aspects of the RAS to evaluate, but the RAS “classification” should ultimately be based on the RAS definition. For R4.3, ATC proposes to replace “satisfies the requirements of Category P7 in Table 1 of NERC Reliability Standard TPL-001-4, or its successor” with rewording such as, “is allowed to result in an interruption of firm Transmission Service or Non-Consequential Load Loss”. This wording is simpler and more straightforward and would not be subject to change if a successor of TPL-001-4 does not include a Category P7, changes the Category P7 contingency, or changes the associated performance requirements.

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6 -

Selected Answer: No

Answer Comment:

Requirement R4 mandates the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, as well as the BES performance following an inadvertent operation of the RAS.

The drafting team considered the RAS classification systems used by several Regions to be rooted in PRC-012, Requirement R1, R1.4. which reads: *"Requirements to demonstrate 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."* Although, the drafting team is not proposing to use formal RAS classifications, the intent of PRC-012, Requirement R1, R1.4. is retained in Requirement 4 and Attachment 1.

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: No

Answer Comment:

The Standard should classify RAS because the current language will lead to subjectivity, ambiguity, and disagreements between RCs and RAS-entities. This will lead to inconsistent application for appropriate levels of security, dependability, and redundancy and the associated level of review required. If a RAS is not classified, these issues (i.e. in the sentence above) become too subjective. It is current practice in the industry to have various classifications for this very purpose. Dependability and security are not defined terms in the NERC glossary.

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Requirement R6 mandates each RAS-owner analyze each RAS operation or failure of a RAS to operate to identify performance deficiencies. Question 7 pertains to Requirement R6.

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - ISO New England, Inc. - 2 - NPCC

Selected Answer: No

Answer Comment:

There does not seem to be any sort of differentiation for the design requirements of various RAS. It is a one-size-fits-all approach; therefore there really are no different categories.

While not specifically reference, the third checkbox in Attachment 2, Implementation, will require every RAS to be fully redundant. Is says that with a single component failure, the BES must meet the same requirements that drove the need for the RAS. Even if failure of the RAS has minimal impact, failure of the RAS would cause the BES not to meet performance requirements or the RAS wouldn't have been needed.

Requirement R6 mandates each RAS-owner analyze each RAS operation or failure of a RAS to operate to identify performance deficiencies. Question 7 pertains to Requirement R6.

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

SPP has a small number of RAS and doesn't have much input on the concept of RAS "classification".

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Oncor Electric Delivery - 2 - TRE

Selected Answer: Yes

Answer Comment:

Is the intent of this standard to create projects or Contingency plans to mitigate RAS misoperations?

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

R4.3 makes reference to performance requirements of Category P7 in Table 1 of NERC Reliability Standard TPL-001-4, or its successor. Can we infer that those performance requirements are the same as in Category P2-4 and Category P4-6?. This requirement could be quite difficult to test depending on the type of RAS.

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eric Senkowicz - Florida Reliability Coordinating Council - NA - Not Applicable - FRCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Without defined “classifications”, all RAS require the same attention by the standard’s requirements.

It seems the ‘Determination of Review Level’ in Attachment 2 also accomplishes the objectives of RAS classifications by determining the level of system response (i.e. determining Significant vs. Limited).

However, the language of Requirement R4 and Attachment 1 (and Attachment 2 as indicated in the comment preceding) accomplish the

	objectives of RAS classification without having a formal RAS classification system. This is particularly important to regions that already employ a classification system, thereby avoiding multiple and overlapping classifications. A classification system is needed to easily communicate the risk and impact of a RAS. Classification, if included in the database, would facilitate an understanding of the risk posed by the various RAS schemes deployed in the BES. Without a classification system for RAS, all RASs are treated equally; this gives the RC (or whomever is eventually assigned responsibility for evaluating them) too much latitude in interpreting an adequate level of redundancy, which would almost invariably lead to inappropriate design.
Document Name:	
Likes:	0
Dislikes:	0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer:	No

Answer Comment:

Tri-State has three concerns here.

First, “planning area” is not defined. We recommend changing the first sentence of R4 to:

“Each Transmission Planner shall perform an evaluation of each RAS for which they have planning responsibilities at least once every…”

Second, it is not clear what is meant by “inadvertent operation of the RAS”. RASs commonly operate more than one facility (see WECC RAS-1). Does this mean the entire RAS or each individual component?

Third, Tri-State also do not agree with the criteria that inadvertent operation of the RAS must satisfy the same performance requirements as those required for the contingency for which it was designed. There are existing RASs that could not meet this requirement.

For example, there are Generator Owners that elect to install RASs that trip (verses re-dispatch) their generator(s) to prevent overloading transmission lines following a single element outage in lieu of upgrading the transmission network. TPL-001-4 does not allow interruption of Firm Transmission Service for P1 contingencies. Since this type of RAS is to mitigate a P1 caused overload, inadvertent operation of the RAS cannot interrupt Firm Transmission Service either. This would not meet the criteria that the RAS must satisfy the same performance requirements as those required for the contingency for which it was designed.

To address the second and third concerns above, Tri-State recommends simplifying R4.3 to:

“The inadvertent operation of any portion of the RAS does not cause a violation of an established Operation’s or Planning horizon System Operating Limit.“

Document Name:

Likes: 0

Dislikes: 0

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

We do not believe it is necessary to classify RAS. RAS is a defined term that should clearly identify the vast majority of RAS. If a regional entity, Planning Coordinator, or Reliability Coordinator wants to continue classifying and tracking RAS, there is nothing in the standard that prohibits this even though it is not necessary for reliability.

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer: No

Answer Comment:

1) Hydro One Networks Inc.:Regions or individual RCs could have their internal/regional Typing, with different design requirements for different Types.

2) Hydro One Networks Inc. agrees with NPCC on the following: *Without a classification system for RAS, all RASs are treated equally; this gives the RC (or whoever is responsible for evaluating) too much latitude in interpreting an adequate level of redundancy, which could easily lead to an inappropriate RAS design.*

Document Name:

Likes: 1 Hydro One Networks, Inc., 1, Farahbakhsh Payam

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment:

HQT proposes that requirements for redundancy, testing and maintenance be different for “limited-impact” RAS versus “high impact” RAS. HQT believes that the standard shall retain the following recommendation from the SPCS report: …it may be appropriate to establish less stringent requirements pertaining to monitoring or single component failure of SPS that present a lower reliability risk. This recommendation is aligned with industry practice. Some RAS are installed for NERC standard compliance, but their impact is very limited to a contained area. Other RAS are critical so wide-area problems for which a much higher reliability of the RAS needs to be achieved through more rigorous design (redundancy and security), maintenance and testing.

HQT agrees with the removal of a formal classification from a NERC standpoint, allowing the regions flexibility to have their own classification. However, regarding the performance for inadvertent operation, requirement 4.3 and Attachment 1 do not provide any consideration of security in the implementation.

If redundancy is an appropriate measure to demonstrate that failure of a single component does not prevent from meeting the TPL standards requirements through the design of a RAS, then it should be possible to demonstrate that inadvertent operation of a component of a RAS does not prevent from meeting P7 from TPL 001-4 through the design review. In that sense, the R3 rationale states that “The review by the RC is intended to identify reliability issues that must be resolved before the RAS can be put in service. The reliability issues could involve dependability, security, or both. A more detailed explanation of dependability and security is included in the Supplemental Materials section of the standard.” No further reference to security is made anywhere in the standard. As for the single component failure requirement, the inadvertent operation requirement should be linked to the design of the RAS.

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Requirement R6 mandates each RAS-owner analyze each RAS operation or failure of a RAS to operate to identify performance deficiencies. Question 7 pertains to Requirement R6.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Texas RE recommends changing the phrase “avoids adverse interactions” to something less vague.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

1) Hydro One Networks Inc.:Regions or individual RCs could have their internal/regional Typing, with different design requirements for different Types.

2) Hydro One Networks Inc. agrees with NPCC on the following: *Without a classification system for RAS, all RASs are treated equally; this gives the RC (or whoever is responsible for evaluating) too much latitude in interpreting an adequate level of redundancy, which could easily lead to an inappropriate RAS design.*

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Requirement R6 mandates each RAS-owner analyze each RAS operation or failure of a RAS to operate to identify performance deficiencies. Question 7 pertains to Requirement R6.

Document Name:

Likes: 0

Dislikes: 0

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Requirement R6 mandates each RAS-owner analyze each RAS operation or failure of a RAS to operate to identify performance deficiencies. Question 7 pertains to Requirement R6.

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: No

Answer Comment:

Attachment 2 generally accomplishes the objective of RAS "classification." However, confirmation by the drafting team is requested that "unplanned tripping of load or generation" refers to tripping of load or generation beyond that identified for another contingency (e.g., breaker failure or bus Fault) as opposed to simply unintentional or inadvertant tripping.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rico Garcillano - Pacific Gas and Electric Company - NA - Not Applicable - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

7. RAS Operational Analyses (Requirement R6): Requirement R6 mandates each RAS-owner analyze each RAS operation or failure of a RAS to operate to identify performance deficiencies Do you agree that the application of Requirement R6 and its Parts would identify performance deficiencies in RAS? If no, please provide the basis for your disagreement and an alternate proposal.

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer: No

Answer Comment:

See response to Question #8.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We agree that the application of R6 would identify deficiencies, but there is a disconnect between the Rationale Box and R6. The Rationale Box says RAS operations and Mis-operations “should” be analyzed while R6 states they “shall” be analyzed. The Rationale Box should be revised to state that RAS Operations and Mis-operations **must** be analyzed.

The analysis of the RAS and identification performance deficiencies would need to include the contribution of RAS-owners, applicable TOPs and applicable TPs to be complete and adequate. In addition, the contribution of any or all of these entities may be needed to identify suitable and valid corrective action options. The RAS-owner should be the entity to choose the option to submit to its reviewing RC (R7).

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Answer Comment:

AEP agrees with the application of R6 as the time frame for analysis, which aligns with R1 in PRC-004-4.

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

We agree with R6 to require the RAS-Owner to conduct the analysis but suggest that the RC should be added to this requirement (or in a new requirement) to review and concur with the analysis results (or request modifications or additional information).

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment:

ATC recommends that R6 (analyze RAS operations or misoperations) should involve the affected TP, TOPs and RAS-owners. If the RAS-owner is selected to be the lead for these analyses, then consider wording like, “Each RAS-owner, in conjunction with affected Transmission Planners and Transmission Operators shall analyze . . .“ Affected TPs and TOPs have knowledge and capabilities to assess the system impacts of a RAS in the planning horizon and operating horizon that RAS-owners do not have. The analysis of the RAS and identification performance deficiencies would need to include the contribution of RAS-owners, applicable TOPs and applicable TPs to be complete and adequate.

ATC recommends a “90-calendar day” time frame in R6, rather than “120-calendar day” timeframe or state as “a timeframe mutually agreed upon with its RC” is incorporated into the requirement.

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6 -

Selected Answer: Yes

Answer Comment:

Requirements R5 and R7 pertain to the submittal of Corrective Action Plans (CAPs) to the Reliability Coordinator (RC) for review, and Requirement R8 mandates the implementation of each CAP. Question 8 addresses these requirements.

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: No

Answer Comment:

If it's a large RAS issue, the timeframe to evaluate should be shorter. In addition, the timeframe to mitigate the issues should be more clearly defined.

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Requirements R5 and R7 pertain to the submittal of Corrective Action Plans (CAPs) to the Reliability Coordinator (RC) for review, and

Requirement R8 mandates the implementation of each CAP. Question 8 addresses these requirements.

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - ISO New England, Inc. - 2 - NPCC

Selected Answer: No

Answer Comment:

Partial operation of an RAS is not listed and should be analyzed. In addition, an RC needs to ability to require the RAS-entity to investigate real time performance issues, such as an RAS that is unavailable on a repetitive basis. In addition, there should be a requirement that that status of the RAS is monitored. Language should be changed as follows:

R6. Within 120-calendar days of each RAS full ***or partial operation*** or each failure of a RAS to operate or an an RAS issue is raised by the RC, each RAS ***entity*** shall analyze the RAS for performance deficiencies. The analysis shall determine whether the: *[Violation Risk Factor:] [Time Horizon:]*

6.1. Power System conditions appropriately triggered the RAS.

6.2. RAS responded as designed.

6.3. RAS was effective in mitigating power System issues it was designed to address.

6.4. RAS operation resulted in any unintended or adverse power System response.

6.5 RAS Owner(s) shall monitor RAS status.

Requirements R5 and R7 pertain to the submittal of Corrective Action Plans (CAPs) to the Reliability Coordinator (RC) for review, and Requirement R8 mandates the implementation of each CAP. Question 8 addresses these requirements.

Document Name:	
Likes:	0
Dislikes:	0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Oncor Electric Delivery - 2 - TRE

Selected Answer: Yes

Answer Comment:

Please elaborate on the definition of an operation used in this context. Are we discussing the relay just arming or are we discussing the whole sequence of operations involved in the RAS?

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

ERCOT agrees that the RAS entity should evaluate RASs under the circumstances identified in Requirements R5 and R6, but would suggest that such entities be required to provide the results of such assessments to their Reliability Coordinator and Planning Coordinator.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer: No

Answer Comment:

RAS-entity should be responsible for R6 instead of RAS-owner. The RAS-entity, being designated to represent all RAS-owners, is in the best position to evaluate the operation of a RAS.

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eric Senkowicz - Florida Reliability Coordinating Council - NA - Not Applicable - FRCC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Similar to PRC-004-3 Protection System Misoperation Identification and Correction, when a RAS operates or fails to operate it should be reviewed.   It is too simplistic to say each RAS-owner will analyze a RAS operation, especially if the RAS implicates components owned by different entities, like a TO, DP, GO, and where the appropriate entity to review system response is the TP and PC. We also suggest moving Parts 6.1 to 6.4 to either the Rationale for Requirement R6, or the Technical Guidelines and out of the requirement.

Agree with R6 as far as it goes. However, the RAS owner may not be in the position to evaluate Parts 6.3 and 6.4. The applicability of these sub-Parts should include the RC.

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

While we agree that R6 is necessary and its application will certainly identify performance deficiencies, we are concerned how an applicable entity will provide compliance with “each failure of a RAS to operate.” We urge the drafting team to avoid creating another “prove the negative” requirement. Will the applicable entity have to retain 6-second scan data for every hour of every year to demonstrate that no conditions ever existed that would have triggered a RAS? This is not reasonable and should be modified.

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: No

Answer Comment:

It is more efficient for the RAS-entity to initially evaluate each RAS operation, and then involve the RAS-owner(s) as appropriate. We request a change to "Within 120-calendar days of each RAS operation or each failure of a RAS to operate, the RAS-entity shall analyze the RAS for performance deficiencies. Each RAS-owner shall cooperate in this RAS-entity led analysis, as needed. …"

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer: No

Answer Comment:

1)Hydro One Networks Inc. believes that the term “performance deficiencies” and requirements R6.1-R6.4 seem to be more related to design of the RAS. It is not clear if a misoperation of an associated relay, DC system , AC circuitry, etc., are included in this requirement. Note that the “new” definition of RAS states that it is a ‘scheme’ and not a ‘protective system’ as is originally defined in SPS which would include the relays, DC system, AC sensing devices, etc.

2) Hydro One Networks Inc. agrees with NPCC on the following: We *agree with R6 and its Parts; however, the RAS owner will not be in the position to evaluate R6.3 and R6.4. The* *applicability of these sub requirements should include the RC.*

3) Hydro One Networks. Inc. further agrees with NPCC on the following: *A requirement cannot be assigned to more than one functional entity. Thus, this requirement should be structured similar to PRC-004-3, where individual requirement for each step of the sequence involved in evaluating operation and misoperation.*

Document Name:

Likes: 1 Hydro One Networks, Inc., 1, Farahbakhsh Payam

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment:

HQT agrees with the intent of R6. However, it seems like this requirement is trying to cover two very different aspects related to RAS operation: RAS equipment and system performance. The burden of the whole evaluation is assigned to the RAS-owner, which is probably best-suited to perform the evaluation of 6.2 RAS responded as designed, but not 6.3 and 6.4 which are related to system response analysis. This would probably be better addressed another entity (RC? TOP?). HQT recommends splitting R6 in two distinct aspects: equipment performance and System performance, and to assign the appropriate entity for both.

R6.1 is redundant with R6.2. If the RAS responded as designed, then Power System conditions appropriately triggered the RAS.

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE is concerned that with a 60 month evaluation timeframe specified in R4, there could be changes that affect the RAS that are not evaluated until the 60 months or an operation of the RAS. A new transmission line could be built where the RAS was not considered and the RAS operates unnecessarily because of the new line.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

1)Hydro One Networks Inc. believes that the term “performance deficiencies” and requirements R6.1-R6.4 seem to be more related to design of the RAS. It is not clear if a misoperation of an associated relay, DC system , AC circuitry, etc., are included in this requirement. Note that the “new” definition of RAS states that it is a ‘scheme’ and not a ‘protective system’ as is originally defined in SPS which would include the relays, DC system, AC sensing devices, etc.

2) Hydro One Networks Inc. agrees with NPCC on the following: We *agree with R6 and its Parts; however, the RAS owner will not be in the position to evaluate R6.3 and R6.4. The* *applicability of these sub requirements should include the RC.*

3) Hydro One Networks. Inc. further agrees with NPCC on the following: *A requirement cannot be assigned to more than one functional entity. Thus, this requirement should be structured similar to PRC-004-3, where individual requirement for each step of the sequence involved in evaluating operation and misoperation.*

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Requirements R5 and R7 pertain to the submittal of Corrective Action Plans (CAPs) to the Reliability Coordinator (RC) for review, and Requirement R8 mandates the implementation of each CAP. Question 8 addresses these requirements.

Document Name:

Likes: 0

Dislikes: 0

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Requirements R5 and R7 pertain to the submittal of Corrective Action Plans (CAPs) to the Reliability Coordinator (RC) for review, and Requirement R8 mandates the implementation of each CAP. Question 8 addresses these requirements.

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rico Garcillano - Pacific Gas and Electric Company - NA - Not Applicable - WECC

Selected Answer: No

Answer Comment:

R6 will address after-the-fact performance deficiencies.

R4 will determine if a scheme is still needed and effective. For new schemes, they will be designed correctly, but if a "grandfathered" scheme is still needed and effective per the TP studies, a flawed design in implementing the scheme could be easily overlooked since the design aspect of a scheme may not be part of a TP review.

Making updating Attachment 1 part of R4 a requirement could address this.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

8. Corrective Action Plans (Requirements R5, R7, and R8): Do you agree that the application of Requirements R5, R7, and R8 would address the reliability objectives associated with CAPs? If no, please provide the basis for your disagreement and describe an alternate proposal.

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer: No

Answer Comment:

The inclusion of both RAS-entities and RAS-owners in this draft standard is problematic. We suggest that the standard is simpler and more effective if the Applicability is limited to a single equipment-owning entity. This single RAS entity should be the equipment-owning entity having the wide-area perspective of the BES, which is normally the Transmission Owner. R5, R6, R7, and R8 will likely be ineffective and unnecessarily complicated when there are multiple RAS-owners. The RAS-entity described above should be assigned the responsibility to submit an overarching Corrective Action Plan (R5 and R7), to analyze RAS operations (R6), and to implement the CAP (R8) based on its discussion and cooperation with the multiple RAS-owners.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

While we agree that application of the requirements would address reliability objectives, we have a few concerns:

- Both R5 and R7 relate to RAS's that are in service, and in both cases deficiencies have been found. We believe 6 months is too long to submit a CAP to the RC. There has already been a significant amount of time since the RAS was found deficient and 3 months should be adequate time to develop a CAP. This is a critical function and there is risk to having it operational when it is known to have deficiencies.
- Nowhere does the RC need to review the CAP in a specified timeframe and agree that it solves the problem(s) identified, and issue a formal statement to that effect. There should be requirement for that step. A RAS owner would be unwilling to implement a CAP unless the RC agreed that it is adequate.
- Requirement 7 should be revised to say: ". . .each RAS-Owner shall submit a Corrective Action Plan for review and approval by its reviewing Reliability Coordinator(s)."

To assure that the CAPs submitted per R5 and R7 are suitable and valid CAPs to address the associated reliability objectives, the CAP must be chosen from CAP options that any or all of the applicable RAS-owners, applicable TOPs, and applicable TPs have determined are suitable and valid CAP options. The identification of suitable and valid CAP options should be included in R4 and R6.

Document Name:	
Likes:	0
Dislikes:	0

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

Answer Comment:

We generally agree with the application of R5, R7 and R8 would address the reliability objectives associated with CAPs, but R8 should be revised to provide a time frame for completing the implementation as otherwise, a CAP's implementation can be deferred indefinitely.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment:

ATC proposes that R5 require TPs to identify suitable and valid CAP options to address any identified deficiencies in R4 and provide these options to the applicable RAS-owners. ATC also proposes adding a requirement (or expand R5) to require RAS-owners to choose one of the viable options and submit their choice to their reviewing RC for approval. Also, ATC proposes adding a new requirement (or expanding R5) to require each RC to accept or reject any CAPs that are submitted by RAS-owners.

ATC suggests a “90-calendar days” time frame, rather than “six full calendar months” timeframe or rewording such as “or a timeframe mutually agreed upon with its RC” is incorporated into R5. A quicker resolution of any deficiency would be better and only allow more time when it is really needed.

ATC suggests that R7 (and any new requirements) be revised similar to the proposals related to R5. Require TPs be required to identify suitable and valid CAP options to address any identified deficiencies in R6 and provide these options to the applicable RAS-owners. Require RAS-owners to choose one of the viable options and submit their choice to their reviewing RC for approval. Require each RC to accept or reject any CAPs that are submitted by RAS-owners.

Document Name:	
Likes:	0
Dislikes:	0

Brian Bartos - CPS Energy - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6 -

Selected Answer: Yes

Answer Comment:

Requirement R9 mandates each RAS-owner periodically perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. Question 9 pertains to Requirement R9.

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: No

Answer Comment:

R8 should include language that the CAPs must be approved by the RC and not merely submitted.

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Requirement R9 mandates each RAS-owner periodically perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. Question 9 pertains to Requirement R9.

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - ISO New England, Inc. - 2 - NPCC

Selected Answer: No

Answer Comment:

We generally agree with the application to address reliability but an R5 and R7 CAP submittal should be made by the RAS entity, it should not be submitted to the RC by multiple RAS Owners.

R5. Within six full calendar months of being notified of a deficiency in its RAS based on the evaluation performed pursuant to Requirement R4, ***the RAS-entity*** shall submit a Corrective Action Plan to its reviewing Reliability Coordinator(s). *[Violation Risk Factor:] [Time Horizon:]*

R7. Within six full calendar months of identifying a performance deficiency in its RAS based on the analysis performed pursuant to Requirement R6, ***the RAS-entity*** shall submit a Corrective Action Plan to its reviewing Reliability Coordinator(s). *[Violation Risk Factor:] [Time Horizon:]*

Requirement R8 should include a timeframe for implementing the CAP.

R8. For each CAP submitted pursuant to Requirement R5 and Requirement R7, each RAS owner shall implement the CAP ***within 90 days unless an alternative alternate schedule is approved by the RC***. *[Violation Risk Factor:] [Time Horizon:]*

Requirement R9 mandates each RAS-owner periodically perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. Question 9 pertains to Requirement R9.

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Oncor Electric Delivery - 2 - TRE

Selected Answer: Yes

Answer Comment:

However, for consistency, I believe that the 120 days in requirement R6 should be changed to 4 months instead of 120 calendar days to be consistent with the other dates in the standard. Although it is much easier to keep track of the days.

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

ERCOT supports the comments of the SRC for these requirements.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer: No

Answer Comment:

R5 and R7 should specify a CAP is created only if deficiency is on the RAS-owners part of the RAS. As written, all RAS-owners would be responsible for submitting CAPs if a single deficiency was identified on just one part of the RAS. As written, a RAS-owner would be responsible for writing a CAP (R5 or R7) and implementing the CAP (R8) for something they may have no control over, if the deficiency is on another RAS-owners part of the RAS.

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: No

Answer Comment:

While we agree with the development of the CAP meeting the intent of R5,R7, and R8, the plan should be provided to the collaborative forum, on which the RC and PC participate.

Document Name:

Likes: 0

Dislikes: 0

Eric Senkowicz - Florida Reliability Coordinating Council - NA - Not Applicable - FRCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

See previous comment on the RC's being inappropriate first line evaluators of RASs.

Document Name:

Likes: 1 Florida Municipal Power Agency, 3,4,5,6, Gowder Chris

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

In addition to the “six full calendar month(s)” submission periods, periods for acceptable implementation of the CAP should be specified. A statement should be included in requirement R5 to address the situation when a RAS-owner disagrees with the Transmission Planner’s evaluation of a RAS.

Requirement R7 should be changed from “submit Corrective Action Plan to its reviewing Reliability Coordinator(s)” to “RAS-entity provide notice to the affected RC and TOP of the deficiency and when the deficiency is planned to be corrected”. This is good practice to keep operators aware of a change in RAS performance.

A requirement should be added to notify the RC and TOP when the RAS is performing correctly after the CAP has been completed.

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

While we have no issue with documenting and developing a CAP, we do not understand the need to submit a CAP to an RC. The RC is not the equipment owner and may not understand the details of the CAP. What purpose is served by submitted the CAP? Any purpose such as notifying the RC of the dates when the RAS will be repaired or how contingencies should be modified in real-time contingency analysis to reflect the deficient operation of the RAS can be handled via other

	means. The responsible entity that develops the CAP should maintain and update the plan, which would be available for auditors to review. We also are concerned that R8 could prevent a CAP from being modified. If the applicable entity must implement the CAP, that implies the moment a CAP is finalized that the measure of compliance begins. Thus, if an applicable entity adds a one month delay to a CAP due to the inability to schedule the work or get parts, they would be in technical violation of the requirement. The standards drafting team modifying PRC-004 has already addressed this issue. We suggest this drafting team adopt their approach which is used in PRC-004-4 R6.
Document Name:	
Likes:	0
Dislikes:	0

Chris Scanlon - Exelon - 1 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Exelon thinks there should be an attempt to specifiy a "time not to exceed" for implementing the corrective action following an RAS performance issue. We understand that the mitigation could cover a wide range of issues but putting no limit on the mitigation seems problematic.

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer: No

Answer Comment:

Hydro One Networks Inc. believes that the standard should:

•□□□□□□□□ (R5 and R7) Clearly specify that CAP shall include work (corrective actions) and the work schedule (target completion date). This is written in the rationale for R8, but is not specified in the body of the standard.

Requirements are not clear on what to do in case a CAP changes. Does the RAS-entity need to resubmit changes in CAP (work or work schedule)?

Document Name:

Likes: 1 Hydro One Networks, Inc., 1, Farahbakhsh Payam

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: Yes

Answer Comment:

A schedule for implementation should be part of R8 (or R5 and R7).

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: No

Answer Comment:

R5 has the incorrect functional entity identified. Manitoba Hydro believe that in most cases, the Transmission Planner identifies the need for the RAS as part of the TPL assessments or other technical studies. If the TP performs a five year assessment and finds the RAS does not work as originally intended, we believe the TP is in the best position to develop a corrective action plan. Such a plan might be to change logic or possibly require faster operation speed. This plan would be tested and functional specifications developed and given to the RAS owner. The RAS Owner would determine the construction schedule, feasibility and cost of the required changes. The TP would then decide whether the RAS should be retained and modified or another change implemented. The TP should be submitting the Corrective Action Plan to the RC in R5 and not the RAS Owner. The RAS-Owner will submit the functional modification changes to the RC as part of R1, if the RAS is to be changed.

It seems unnecessary to include Requirement R8 in the standard. Requirement R5 and R7 already identify the need for the CAP and the RC is informed. The RC is in the best position to identify possible actions in real time (system readjustments) if the CAP is not implemented in a timely manner. TPL-001-4 will catch any contingencies (P1-P7) that do not meet the performance requirements in Table 1. This requirement appears to be redundant and will only serve to penalize an entity multiple times for the same issue.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE recommends a requirement for reviewing and approving a Corrective Action Plan. If the RC does not review the CAP, the CAP might not be sufficient and could create a reliability gap.

Texas RE is concerned that the timeframes in this standard are too lengthy:

- A 60 month evaluation of RAS per R4;

- A CAP submitteal within six full calendar months of being notified of a deficiency in RAS per R5;
- An analysis of RAS within 120 calendar days per R6;
- CAP submittal within six full calendar months per R7; and
- No time limit on implementing the CAP per R8 so a performance deficiency affecting reliability could go uncorrected for years and entities would remain compliant.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

Hydro One Networks Inc. believes that the standard should:

•□□□□□□□□ (R5 and R7) Clearly specify that CAP shall include work (corrective actions) and the work schedule (target completion date). This is written in the rationale for R8, but is not specified in the body of the standard.

•□□□□□□□□ Requirements are not clear on what to do in case a CAP changes. Does the RAS-entity need to resubmit changes in CAP (work or work schedule)?

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Requirement R9 mandates each RAS-owner periodically perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. Question 9 pertains to Requirement R9.

Document Name:

Likes: 0

Dislikes: 0

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

We generally agree with the application of R5, R7 and R8 would address the reliability objectives associated with CAPs, but R8 should be revised to provide a time frame for completing the implementation as otherwise, a CAP's implementation can be deferred indefinitely.

Requirement R9 mandates each RAS-owner periodically perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. Question 9 pertains to Requirement R9.

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: Yes

Answer Comment:

Under Requirement R5, it seems like the CAP should also be submitted to the Transmission Planner because they identified the issue in the first place.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rico Garcillano - Pacific Gas and Electric Company - NA - Not Applicable - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

9. Functional Testing of RAS (Requirement R9): Do you agree that functional testing of each RAS would verify the overall RAS performance and the proper operation of non-Protection System components? If no, please provide the basis for your disagreement and describe an alternate proposal.

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer: No

Answer Comment:

As above, the RAS-entity with overall BES system view should be responsible to perform testing of the RAS, based on input from the other RAS-owners.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

The six calendar years interval is not compatible with the intervals associated with the different kinds of components that may be in a RAS. Consider wording like, “replace “proper operation of non-Protection System components” proper operation of components that do not perform a System Protection function. Capacitor bank switching control, transformer tap changer control, phase shifter control, and generation runback control.   Is there already a specific requirement in PRC-005-2 that covers the non-Protection System components of a RAS (PLCs may be used in a RAS, but these are not specifically covered in PRC-005-2). We propose that R9 be removed from PRC-012-2 and moved to PRC-005 (or a new PRC Standard that addresses non protective components) standard, so all the maintenance and testing requirements are consolidated in one place, rather than having a few outliers.

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:

AEP does not believe that R9 should be included in PRC-012-2. If anywhere, it should instead be included in PRC-005. A similar requirement exists within the SPR maintenance obligations of PRC-005-4, which requires non-electrical components to be maintained every 72 months. If there are special testing requirements for non-protection system components associated with RAS, then they should be included in PRC-005 where all the other maintenance and testing is identified

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment:

Functional testing of RAS is a maintenance activity that would be better included in the PRC-005 standard. The present PRC-005-2 Reliability Standard is the maintenance standard that replaces PRC-005-1, 008, 011 and 017 and was designed to cover the maintenance of SPSs/RASs. However, Reliability Standard PRC-005-2 lacks intervals and activities related to non-protective devices such as programmable logic controllers. ATC recommends that a requirement for maintenance and testing of non-protective RAS components be added to a revision of PRC-005-2, rather than be an outlying maintenance requirement located in the PRC-012-2 Standard.

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6 -

Selected Answer: Yes

Answer Comment:

Requirements R10 and R11 pertain to the RAS database, Attachment 3, and the sharing of RAS information for reliability-related needs. Questions 10 11, 12, and 13 pertain to these topics.

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Requirements R10 and R11 pertain to the RAS database, Attachment 3, and the sharing of RAS information for reliability-related needs. Questions 10 11, 12, and 13 pertain to these topics.

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - ISO New England, Inc. - 2 - NPCC

Selected Answer: Yes

Answer Comment:

Requirements R10 and R11 pertain to the RAS database, Attachment 3, and the sharing of RAS information for reliability-related needs. Questions 10 11, 12, and 13 pertain to these topics.

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

We would like the SDT to discuss the possibility of using either actual operation of the RAS that was found to be functionally correct or perhaps maintenance testing of the RAS to reset the six-year testing requirement.

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Oncor Electric Delivery - 2 - TRE

Selected Answer: No

Answer Comment:

Although functional testing would verify that the scheme is working as designed, there is no reason to believe that an RAS is any different from another protection system i.e., it would need to be tested at intervals outside the normal maintenance program. The testing of RAS should fall in line with PRC-005-3 requirements for monitored systems and unmonitored systems.

By requiring “at least once every six calendar years, each RAS-owner shall perform a functional test,” the drafting team is forcing all owners of a RAS that has any Protection Systems in it to abandon the PRC-005-3 12 year Maximum Maintenance Intervals allowed in tables 1-1, 1-2, 1-3, 1-5, and 4.

If Requirement R9 is adopted as stated in this draft of the standard, each segment of a RAS would have to be tested at a maximum interval of 6 calendar years. This would require, for example, that voltage and current sensing devices providing inputs to protective relays of a RAS “shall” be tested “at least once every six calendar years” instead of 12 Calendar years allowed in Table 1-3 of PRC-005-3.

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

ERCOT agrees with the need to test the functionality of RASs; however, it recommends that such testing be coordinated with the RC and that the RC be provided with the results of such testing and any associated corrective actions or modifications that are determined by the RAS entity to be necessary following such testing.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Duke Energy requests further explanation on the benefit of performing "functional testing" as opposed to what is tested currently in PRC-005 and what exactly will be required to be performed outside of what is already performed via the required PRC-005 functional testing. It appears that there may be some redundancies in testing between PRC-012-2 and PRC-005.

Also, R9 adds additional maintenance activities for a RAS beyond the PRC-005-3 requirements. PRC-012 requires that an entity verify

the proper operation of the non-Protection System (control) components of a RAS that are not addressed in PRC-005. It will also require that an entity verify the overall RAS performance. This would be difficult to plan and coordinate, and in some cases would cause intentional and significant system perturbation as well as potential loss of customer load.

Lastly, as written, the supplement sounds like an entity is expected to simulate an out-of-step/power swing condition, and test the internal logic of the SEL relays, which is beyond anything that currently performed for PRC-005. Is this interpretation accurate? If this is accurate, Duke Energy disagrees with the inclusion of such maintenance activities in a separate standard, and believes that all maintenance activities should be kept in one document (PRC-005).

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: No

Answer Comment:

There needs to be additional definition on what constitutes a functional test. It is not clear what it mean by “non-Protection System components”. We would not want to trip generators or load as part of this.

Document Name:

Likes: 0

Dislikes: 0

Eric Senkowicz - Florida Reliability Coordinating Council - NA - Not Applicable - FRCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

This would be difficult and in some cases would cause intentional and significant system perturbation as well as potential loss of customer load.

Document Name:

Likes: 1 Florida Municipal Power Agency, 3,4,5,6, Gowder Chris

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

We agree with the segmented testing approach. A Technical Guideline may be required to explain how the six year cycle is measured when allowing segmented testing. Segmented testing can test all components of an RAS every six years, but an individual component could end up being tested once every 10 years; for example, tested in year 1 and year 10.

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

In order to better align with the Rationale provide for R9, Tri-State suggests the following changes to the Requirement and the associated Measure:

Requirement 9: Each RAS-owner shall perform a functional test of each individual segment of each RAS at least once every six calendar years per segment, or at least once every six calendar years shall perform a functional test of each RAS, to verify the overall RAS performance and the proper operation of non-Protection System components. A correct operation of the RAS would qualify as a functional test."

Measure 9: "Acceptable evidence may include, but is not limited to, date-stamped documentation of the functional testing of the entire RAS, or of the individual segments of the RAS. Alternatively, acceptable evidence may also include date stamped documentation of a correct operation of the entire RAS or of the individual segments of the RAS."

Document Name:

Likes: 0

Dislikes: 0

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We are concerned that this requirement will create redundancies with PRC-005. As an example, PRC-005 already requires the applicable entity to verify the output of protection relays that are part of RAS in Table 1-1 and to verify all paths of control circuits in Table 3 every 12 calendar years. Furthermore, the periodicity associated with R9 is not consistent with the tests required in PRC-005. If R9 persists, these redundancies should be removed from PRC-005.

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer: No

Answer Comment:

1) Hydro One Networks Inc. agrees with NPCC with the following: *any maintenance activities associated with RAS should* ***not*** *appear in this standard. The functional testing approach attempted in this standard is found to be unworkable and confusing. The only alternative proposal is to have all maintenance activities associated with RAS in a future revision of PRC-005.*

Document Name:

Likes: 1 Hydro One Networks, Inc., 1, Farahbakhsh Payam

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: Yes

Answer Comment:

HQT understands the intent of R9, but having testing and maintenance of RAS covered in two separate standards (PRC-005-3 and PRC-012-2) is confusing and unpractical. NERC should seriously consider covering the testing and maintenance of every component of a RAS within the same standard.

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE does not agree that RAS is not a protection system component. Texas RE recommends that there is a requirement to test RAS components. Texas RE is concerned that the verbiage “each RAS” will not require entities to functionally test all RAS interactions.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

1) Hydro One Networks Inc. agrees with NPCC with the following: *any maintenance activities associated with RAS should **not** appear in this standard. The functional testing approach attempted in this standard is found to be unworkable and confusing. The only alternative proposal is to have all maintenance activities associated with RAS in a future revision of PRC-005.*

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Requirements R10 and R11 pertain to the RAS database, Attachment 3, and the sharing of RAS information for reliability-related needs. Questions 10 11, 12, and 13 pertain to these topics.

Document Name:

Likes: 0

Dislikes: 0

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Requirements R10 and R11 pertain to the RAS database, Attachment 3, and the sharing of RAS information for reliability-related needs. Questions 10 11, 12, and 13 pertain to these topics

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: Yes

Answer Comment:

It is recommended that RAS maintenance/testing be consolidated into only one standard, either PRC-005 or PRC-012, not both.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rico Garcillano - Pacific Gas and Electric Company - NA - Not Applicable - WECC

Selected Answer: Yes

Answer Comment:

However, the extent of monitoring of the non-protection systems should be considered in allowing for exeptions/extensions.

For example, if a PLC is continuously monitored, the 'health' of the PLC should not be of any concern and a functional test of the PLC should not be required. What could be required though is a functional test of the logic within the PLC. They may not be mutually exclusive in most cases, but it should be considered and left up to the RAS entity to decide.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

10. Choice of Reliability Coordinator (Requirement R10): Do you agree with the Reliability Coordinator being the functional entity designated to maintain the RAS database? If no, please provide the basis for your disagreement, your choice of functional entity, and the rationale for your choice.

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:	Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We agree that the RC may be the best single functional entity to assign the obligation of maintaining a RAS database. However, we suggest that R10 include the obligation to provide information from this database to functional entities that request it and have reliability need for it (e.g. PCs and TPs). Consider wording like, ”. . . provide information from the database to functional entities that request and have a reliability need for the RAS information”.

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Answer Comment:

AEP seeks clarification on line item #3 to ensure the existing evaluation performed by the RRO, in accordance with industry best practice, is the most recent date supporting requirement R2 of this standard.

3. Expected or actual in-service date; ***most recent (Requirement R2)*** *review date; 5-year (Requirement R4) evaluation date; and, date of retirement, if applicable*

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

Answer Comment:

While we agree that the RC is the appropriate entity to maintain the database, pursuant to our comment under Q3 in which we suggest the SDST to consider involving Planning Coordinators in the evaluation process, we suggest the PC also be assigned this task for RASs that have been planned and evaluated in the long-term planning timeframe. Some entities may have a need for planned RAS information for modeling.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment:

ATC agrees that the RC may be the best single functional entity to assign the obligation of maintaining a RAS database. However, ATC suggests that R10 include the obligation to provide information from this database to functional entities that request it and have a reliability need for it (e.g. PCs and TPs). Consider rewording such as,” . . . provide information from the database to functional entities that request and have a reliability need for the RAS information”.

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - ISO New England, Inc. - 2 - NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer:	Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Oncor Electric Delivery - 2 - TRE

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3 - MRO

Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:	Yes

Answer Comment:

While ERCOT agrees that the RC is the appropriate entity to maintain the database, pursuant to its comment under Q3 in which it is suggested that the SDST consider involving Planning Coordinators in the evaluation process, ERCOT suggests the RC be responsible for providing the database to the PC.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Duke Energy questions whether requiring the RC to maintain the RAS database enhances reliability. This requirement can be viewed as an administrative burden on the RC, and we feel that instead of requiring the RC to maintain a database, that the RC should only be required to be familiar with the RAS that exists in its area.

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eric Senkowicz - Florida Reliability Coordinating Council - NA - Not Applicable - FRCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The RCs should not be responsible for the evaluation and coordination of RASs therefore making them in charge of the database of RASs would be inappropriate. The RCs should be notified of RAS installations, modifications and retirements and could have a requirement to acknowledge receipt from the RAS owners on any of the above RAS activities.

Document Name:

Likes: 1 Florida Municipal Power Agency, 3,4,5,6, Gowder Chris

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

This could be the RC or PC; both have a need to know the location and performance characteristics.

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We question the need to have a requirement to maintain a database especially since many of the other requirements cannot be met without information in the database. In essence, the other requirements create an indirect requirement for a database. However, we believe it is actually the PC that should maintain this information if the requirement persists.

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer: No

Answer Comment:

See Q1 above.

Document Name:

Likes:	1	Hydro One Networks, Inc., 1, Farahbakhsh Payam
Dislikes:	0	

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Texas RE recommends aligning Attachment 1 with Attachment 3. The rationale for R10 states that the database will be comprehensive but it isn't comprehensive without the information in both Attachment 1 and Attachment 3.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

See Q1 above.

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

This is an administrative requirement that seems inappropriate for RC entities.

Document Name:

Likes:	0
Dislikes:	0

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Error: Subreport could not be shown.

Selected Answer:	Yes
Answer Comment:	**While we agree that the RC is the appropriate entity to maintain the database, pursuant to our comment under Q3 in which we suggest the SDST to consider involving Planning Coordinators in the evaluation process, we suggest the PC also be assigned this task for RASs that have been planned and evaluated in the long-term planning timeframe. Some entities may have a need for planned RAS information for modeling.** **Note - These SRC comments represent a consensus of the ISOs/RTOs with the exception of ERCOT.**
Document Name:	
Likes:	0
Dislikes:	0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rico Garcillano - Pacific Gas and Electric Company - NA - Not Applicable - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

A method for Regional Entities to transfer information from their existing SPS/RAS databases to the appropriate RC(s) should be considered.

Document Name:

Likes: 0

Dislikes: 0

11. Information listed in Attachment 3 (Requirement R10): Do you agree that the RAS information required in Attachment 3 provides the Reliability Coordinator with enough detail of each RAS to meet its reliability-related needs? If no, please identify what other reliability-related information should be included in Attachment 3 and the rationale for your choice.

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6 -

Selected Answer: No

Answer Comment:

Comments: PacifiCorp represents that it is unable to answer this question without the RC providing more detail about its reliability-related needs.

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: No

Answer Comment:

Attachment 3 should also include other information required by the RC Data Request to allow for information beyond that currently specified in Attachment 3.

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Add RC approval date

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - ISO New England, Inc. - 2 - NPCC

Selected Answer: No

Answer Comment:

Attachment 3 should include a listing of the RAS Owners.

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Oncor Electric Delivery - 2 - TRE

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3 - MRO

Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:	Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

See Duke Energy’s response and comment to question 10.

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer: Yes

Answer Comment:

R10 should include a sub-requirement for RCs to share their database with neighboring RCs to provide coordination of RAS schemes near RC borders.

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: No

Answer Comment:

Besides the initiating condition(s), there should be a sequence of events (actions taken) by the RAS for each condition.

Document Name:

Likes: 0

Dislikes: 0

Eric Senkowicz - Florida Reliability Coordinating Council - NA - Not Applicable - FRCC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

In addition to the detail in attachment 3, it would be important to receive breaker diagrams, list of elements being monitored and actual trigger levels, any associated pre-RAS action alarms, elements being triggered by the RAS (i.e. Breaker at substations, etc).

Document Name:

Likes: 1 Florida Municipal Power Agency, 3,4,5,6, Gowder Chris

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The wording of the lengths of time for meeting a requirement should be consistent. Requirement R4 specifies 60 full calendar months, Attachment 3 Item 3 refers to a 5-year evaluation date.

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:		
Likes:	0	
Dislikes:	0	

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:		
Answer Comment:		
Document Name:		
Likes:	1	Hydro One Networks, Inc., 1, Farahbakhsh Payam

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE recommends aligning Attachment 1 with Attachment 3. The rationale for R10 states that the database will be comprehensive but the data is not comprehensive without the information in both Attachment 1 and Attachment 3.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Although the answer is Yes, it is made in the context of this is information that should be provided as a matter of course to the RC as an area operating entity and NOT because it should be keeping a database or performing a review.

Document Name:

Likes: 0

Dislikes: 0

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rico Garcillano - Pacific Gas and Electric Company - NA - Not Applicable - WECC

Selected Answer: No

Answer Comment:

The expectation should be that "grandfathered" schemes which may never have been presented then be presented to the RC. This will ensure that all schemes (new and existing) adhere to the new requirements and guidelines.

That said, an agreed upon action plan to update the "grandfathered" schemes per the new requirement should be acceptable.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer:

Answer Comment:

TVA supports the comment filed by the SERC Dynamics Review Subcommittee (DRS) on this question.

Document Name:

Likes: 0

Dislikes: 0

12. Requirement R11: Is there a reliability benefit of Requirement R11? Please provide the rationale for your answer.

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Fulfillment of R11 would always provide a reliability benefit because the requirement specified that the requesting entity has to have a reliability-related need for the information.

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Answer Comment:

AEP supports the applicability of R11, however we seek clarification on the requirement to ensure that R11 applies only to RASs that are in-service.

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

Answer Comment:

And please see our comment under Q10 for data that may be required for modeling in the long-term planning timeframe.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer: No

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6 -

Selected Answer:	Yes
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - ISO New England, Inc. - 2 - NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The requirement is duplicative of other information sharing requirements such as TOP-003-3 R5.

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Oncor Electric Delivery - 2 - TRE

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

---

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

However, given the coordination that ERCOT recommends between the RC and PC, it suggests that the provision of data between these entities not be required to be governed on a “request” basis**.**

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

But we believe the Measure and the RSAW should be written such that the RAS-entity is not trying to prove the negative (that they received no request). An attestation of “no requests received” should be sufficient evidence.

Document Name:

Likes: 0

Dislikes: 0

Eric Senkowicz - Florida Reliability Coordinating Council - NA - Not Applicable - FRCC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Is a request to provide information for the database described in R10 supposed to start the 30-day clock indicated in requirement R11? If so, that should be made clear.

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: No

Answer Comment:

While this requirement benefits the entity requesting the information, R11 does not provide a clear system reliability benefit.

Document Name:

Likes: 0

Dislikes: 0

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Requirement R11 is a “in case we forgot an entity that needs the information” requirement. It meets multiple paragraph 81 criteria (B1-Administrative, B4 Reporting, and B7-Redundant). First, it is administrative in nature and creates needless burden on the applicable entity. Who makes the final judgment call on whether a reliability need was demonstrated? The applicable entity? The requester? The auditor? Because of this uncertainty, the applicable entity will spend unnecessary time and resources on demonstrating compliance with a requirement that has questionable reliability benefit. The questionable reliability benefit is even demonstrated by the language of in the supplemental materials on page 21 which begins with “Other registered entities **may** (emphasis added) have reliability-related need.” These materials do not even seem to be sure that there is reliability benefit with the “may” language. Second, it requires reporting information to third parties which appears to provide little reliability benefit. If this requirement does not exist, entities that have the reliability related need for this information still have multiple avenues to get the date (e.g. regional model building processes, via Planning Coordinator, and via a direct request). We simply do not believe an applicable entity will refuse this information to a third party that is a reliability entity and truly has the need for such data. Finally, this requirement is redundant with other requirements in this standard that already require communication of this information to other reliability entities such as the Reliability Coordinator. Please remove this requirement before the first formal posting.

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer: No

Answer Comment:

1)Hydro One Networks Inc.:

Regions and RCs will establish (have established) their own procedures and requirements for exchange of detailed RAS data/model. The requirement for providing general RAS data/model could be handled by the MOD-032 standard.

2)Hydro One Networks Inc. also agrees with NPCC in that: *R11 mandates 30 calendar days for providing requested information for a modelling need--is this intended to apply to Requirement R10 as well for providing information to maintain the database? If so, words must be added.*

Document Name:

Likes: 1 Hydro One Networks, Inc., 1, Farahbakhsh Payam

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: Yes

Answer Comment:

The information provided through R10 is appropriate for a high level view of RAS in a specific area, but is definitely not sufficient if an entity has a reliability need for more information. In that sense, R11 seems justified.

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: No

Answer Comment:

It is not clear at what stage other entities might be involved in the RAS assessment process and require models? Should the RC be responsible for determining whether other entities have a reliability related need for a proposed RAS model rather than the RAS owner?

Would it not be simpler to make this a requirement for the RAS owner to develop a model for all RAS that are required to meet the performance requirements of contingencies P1-P7 in Table 1 of TPL-001-4 and include the model in the NERC model building process (MOD-032-1) or possibly adjacent TPs and PCs can coordinate in developing models through TPL-001-4 (R3.4.1 & R4.4.1)? Better yet, the RAS owner should develop and provide the final tested model to its Transmission Planner and Reliability Coordinator. The TP and RC could share models with adjacent entities as required for reliability purposes.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Texas RE agrees that there is a benefit in sharing information that affects operation of the grid. Texas RE recommends clarifying the term “Reliability-related need”.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

1)Hydro One Networks Inc.:

Regions and RCs will establish (have established) their own procedures and requirements for exchange of detailed RAS data/model. The requirement for providing general RAS data/model could be handled by the MOD-032 standard.

2)Hydro One Networks Inc. also agrees with NPCC in that: *R11 mandates 30 calendar days for providing requested information for a modelling need--is this intended to apply to Requirement R10 as well for providing information to maintain the database? If so, words must be added.*

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

And please see our comment under Q10 for data that may be required for modeling in the long-term planning timeframe.

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: No

Answer Comment:

This requirement seems to assume that RAS-entities need to be mandated to provide the requested information. Is there evidence that RAS-entities will generally avoid providing the requested information? If not, then this requirement imposes an administrative burden with little reliability benefit.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

BPA requests additional clarification of “registered entity” as referenced in R11. This is not a NERC-defined term.

“Within 30 calendar days of receiving a written request from a **registered entity** with a

reliability-related need to model RAS operation, each RAS-entity shall provide the

requesting entity with either the requested information or a written response specifying the basis for denying the request.”

Document Name:

Likes: 0

Dislikes: 0

Rico Garcillano - Pacific Gas and Electric Company - NA - Not Applicable - WECC

Selected Answer: No

Answer Comment:

Assuming the RC Database is up to date, the info in Attachment 3 already provides the same info requested per R11

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

13. Choice of RAS-entity (Requirement R11): Do you agree with the RAS-entity being the entity designated to provide the detailed RAS information to other registered entities with a reliability-related need? If no, please provide the basis for your disagreement, your choice of entity, and the rationale for your choice.

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:	Yes

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer:	Yes
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

Answer Comment:

The standard needs to be more specific how a RAS entity is determined. In addition, the Planning Coordinator should be considered as a RAS-entity (please see our comment under Q10).

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Brian Bartos - CPS Energy - 3 -

Selected Answer:	Yes
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Dominion believes it is appropriate to designate the RAS-entity to provide information contained in Attachment 1. However, if the request is for information contained in Attachments 2 or 3, Dominion believes the designated entity should be the RC.

Document Name:

Likes: 0

Dislikes: 0

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

RAS-owner and RAS-entity should also be NERC defined terms.

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Goodman - ISO New England, Inc. - 2 - NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

RAS-entity is an undefined term and not reflected in the Functional Model. In most cases the entity is probably also a GOP or TOP but could be an entity who is neither of these. Unless the RAS-entity is defined as an identified, enforceable Functional Entity, compliance and reliability authority becomes unclear

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Oncor Electric Delivery - 2 - TRE

Selected Answer: No

Answer Comment:

Since the Regional Entity will be keeping the database on each RAS, there is no need for any entity to go to the RAS Entity for information. This requirement places extra compliance burden on the RAS Entity to provide addition information unnecessarily.

Document Name:

Likes: 0

Dislikes: 0

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: No

Answer Comment:

The RAS-entity being the entity to provide the detailed RAS information to other registered entities should be the Transmission Planner or FRCC Planning Coordinator since they study the reliability impact of the RAS and maintain the system models.

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eric Senkowicz - Florida Reliability Coordinating Council - NA - Not Applicable - FRCC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

We agree there should be one primary equipment owner responsible for submitting the data. However, we believe all requirements applicable to the RAS-owner should actually apply to RAS-entity for simplicity. Otherwise, the simplicity of using a RAS-entity is not realized. Using RAS-entity for only a sub-set of requirements does not reduce the complexity of the standard.

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer: No

Answer Comment:

Hydro One Networks Inc.:

Regions and RCs will establish (have established) their own procedures and requirements for exchange of detailed RAS data/model. The requirement for providing general RAS data/model could be handled by the MOD-032 standard.

Document Name:

Likes: 1 Hydro One Networks, Inc., 1, Farahbakhsh Payam

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: Yes

Answer Comment:

The SDT should consider giving more rationale or guidelines on the roles of the RAS-owner and RAS-entity and how to appropriately define the RAS-entity.

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: No

Answer Comment:

Please see 12 above. The RAS-entity should be confirming the model after functional tests are performed in R9 and providing the model to its Transmission Planner and Reliability Coordinator. The TP and RC are in the best position to use the models and coordinate with adjacent entities in this standard and other standards.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE recommends clarity regarding how an entity is designated a "RAS-entity". It is not clear if it is the same as the RAS-owner. With no requirement to designate a RAS-entity, it is not clear who would be responsible for the reliability requirements if there is no RAS-entity designated.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

Comments: Hydro One Networks Inc.:

Regions and RCs will establish (have established) their own procedures and requirements for exchange of detailed RAS data/model. The requirement for providing general RAS data/model could be handled by the MOD-032 standard.

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Along with the Planning Coordinator (please see our comment under Q10).

Note - These SRC comments represent a consensus of the ISOs/RTOs with the exception of ERCOT.

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rico Garcillano - Pacific Gas and Electric Company - NA - Not Applicable - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

14. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Applicability Section 4.1.4 – The term “RAS-entity” is vague and not self-explanatory. We would prefer that the standard only refer to “RAS-owners” and the requirements use wording like “ each RAS-owner, individually or jointly . . .”. Otherwise, if the representative approach is retained, then we suggest using an alternative label, such as “RAS-agent” or “RAS-representative” to be more closely aligned with the entity’s function.

R1, Rationale, sentence 2 – The definition of “functional modification” should be qualified further with wording like, “is any alteration of a RAS that leads to the performance of a different operational objective or action. The replacement of RAS components, the changing of RAS settings or software upgrade does not modify the RAS functionality, if the intended operational objective or result is achieved.

R3 - We suggest that “mutually agreed upon” be added in R3. The RAS-entity should have some reasonable check and balance to the RC identified reliability related issue.

R5, R6, R7 - We suggest that “or mutually agreed upon time-frame” be added in R5 and R7. The RAS-entity and the RC should have the flexibility to agree upon a time that a corrective action plan is needed based upon workloads and risk. A one-size fits all approach does not benefit system reliability or risk-based concepts.

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Clarity is needed in R4 as to exactly what the trigger is for the 60 full month periodic review. Is it tied, perhaps, to the in-service status? In addition, rather than a 60 full month periodic review, AEP suggests a "5 calendar year" review. This would allow flexibility for an entity to integrate this work into its annual planning cycle.

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:

Answer Comment:

The standard requires only one RC to review the RASs that are located in its area of responsibility. There are RASs that in case of incorrect operation or failure could affect a neighboring entity even if they are located in one area. In these cases should the standard require a coordinated review with the affected neighbors?

The standard requires reviewing of the new or modified RASs. What level of modification would trigger a review for a RAS that was in service before the standard becomes effective? Please specify.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

Applicability Section 4.1.4 – The term “RAS-entity” is vague and not self-explanatory. ATC would recommend that the standard only refer to “RAS-owners” and the requirements be reworded such as “each RAS-owner, individually or jointly . . .” Otherwise, if the representative approach is retained, then we suggest using an alternative label, such as “RAS-agent” or “RAS-representative” to be more closely aligned with the entity’s function.

R1, Rationale, sentence 2 – The description of “functional modification” should be qualified further with wording such as, “is any alteration of a RAS that leads to the performance of a different operational objective or action. The replacement of RAS components, the changing of RAS settings or upgrading software does not modify the RAS functionality, if the intended operational objective or result is achieved.

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Dominion suggests that the explanation from footnote 13, Page 16, from the SCPS Technical Report, be added into the Supplemental material to help identify the purpose of “4.1.4 RAS-entity – the Transmission Owner, Generator Owner, or Distribution Provider designated to represent all owners of the RAS.”

Dominion agrees with the recommendation contained in the SCPS Technical report (page 17) that states “When deciding whether to approve an SPS, the Reliability Coordinator and the Planning Coordinator in whose area the SPS is to be installed or modified should be required to consider supporting information provided with the application; comments from Transmission Planners, Transmission Operators, and Balancing Authorities and other Reliability Coordinators and Planning Coordinators; and any supplemental information provided by the SPS owner. “ and suggests it be incorporated into the Supplemental Material.

Dominion does not see the need to use the word ‘full’ before calendar month in the Supplemental Material and is concerned that its use in this standard could result in uncertainty surrounding the use of calendar month in other standards.

Attachment 1, Section II refers to Table 1, Category P7. What is the relevance to making reference to Category P7 uniquely and specifically (tower line or bipolar DC line)?

Attachment 1, Section III-Implementation states, “Documentation describing the functional testing process.” Dominion recommends deleting this bullet. This information is not necessarily available during the early preliminary design stage. The approval of the design is sought prior to detailed engineering.

Document Name:

Likes: 0

Dislikes: 0

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer:

Answer Comment:

The revised PRC-012 addresses new RAS, retired RAS, and functionally modified RAS. The revised Standard does not address existing RAS, and therefore neglects any potential reliability issues associated with them. Peak believes that existing RAS should not be automatically grandfathered and that there should be a one-time process to review existing RAS in accordance with the new PRC-012.

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Kathleen Goodman - ISO New England, Inc. - 2 - NPCC

Selected Answer:

Answer Comment:

Language in R4 should be changed to allow for an “assessment” to lessen the level of review if no changes occur to the RAS or the area electric system RAS is designed to protect. Suggest the following language:

R4. Each Transmission Planner shall perform an ***assessment*** of each RAS within its planning area at least once every 60 full calendar months and provide the RAS-owner(s) and the Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether: *[Violation Risk Factor:] [Time Horizon:]*

There should be a phased in implementation plan for RC review of existing RAS installations. If the Implementation Plan contemplates a review of all existing RAS installations then that would be an overwhelming task.

R4.3, Attachment 1 and Attachment 2:

All three items state the performance requirements for inadvertent operation of an RAS are the same as those for the condition that it was installed. This is not the correct metric to use. All of the performance requirements in the TPL should be met if there is inadvertent operation.

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Oncor Electric Delivery - 2 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3 - MRO

Selected Answer:

Answer Comment:

MidAmerican has concerns about "redundancy" and "guidance" to steer SPS / RAS designs and mandatory requirements. The language needs to be modified to strike the "appropriate level of redundancy" and replace it with a concept that the "design of the RAS / SPS must meet its performance objective within the TPL requirements even with single component failure. The RAS / SPS just has to survive a single component failure and still achieve its reliability objective. The method or "how" this is achieved should be left to the RAS / SPS owner with input from the regional RC.

MidAmerican suggests that wording in Attachment 1, Section III be modified to concentrate on the "design" of the RAS / SPS rather than specifying a narrow interpretation of redundancy.

"Documentation showing that ***the design of the RAS*** *is such that a single RAS component failure, when the RAS is intended to operate, does not prevent the interconnected transmission system from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the System events and conditions for which the RAS was designed. The documentation should describe or illustrate how the implementation design achieves this objective."*

Document Name:

Likes: 0

Dislikes: 0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment:

As RASs may have an impact in both the long and short-term horizons, ERCOT recommends that the SDT consider revising the standards as set forth above to ensure that such coordination and associated information exchanges occurs.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Duke Energy requests further clarification on the use of varying measurements of time. In multiple places throughout the standard, the drafting team uses the measurement of “full calendar months”. In other places (R6 and R11) the measurement “calendar-days” is used. We request more clarification on the difference between the two, or a revision wherein only one measurement is used for consistency.

Duke Energy suggests that Attachments 1 and 2 be changed from bullets to numbers or letters so every item is referenced clearly and unambiguously.

On Attachment 1. Section III – Implementation. Fourth bullet, Duke Energy suggests moving it to Section II - Functional Description and Transmission Planning Information before the Fifth Bullet.

On Attachment 1. Section II – Functional Description and Transmission Planning Information. The fifth bullet should include language to address “adequate level of redundancy” and “single RAS component failure”. These two definitions are too vague and might lead to very different interpretation depending to the type of RAS.

Duke Energy requests clarification regarding how PRC-012-2 will address the failure to operate and inadvertent operation of a “fully redundant” RAS (i.e.,D12 and D13 in the present TPL standards). If does not appear that they are addressed in the present draft.

Document Name:	
Likes:	0
Dislikes:	0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:

Answer Comment:

No comment.

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eric Senkowicz - Florida Reliability Coordinating Council - NA - Not Applicable - FRCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Our thanks for the drafting team's efforts on trying to improve the clarity of the standards with respect to RASs.

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

The definitions for “Functionally Modified” as used in Attachments 1 and 2 should be included in definitions specifically used in this standard, and not in footnotes.

“Power System” is used throughout the body of the standard. Should it be Bulk Electric System?

Requirement R2 stipulates that each reviewing Reliability Coordinator has four calendar months, or on a mutually agreed upon schedule after receipt of Attachment 1 materials to perform a review of the RAS in accordance with Attachment 2. There should be an upper bound put on a mutually agreed upon schedule to prevent excessively long times for this review to take place.

Requirement R5, as written, suggests that independent Corrective Action Plans should be submitted by each RAS-owner. It is proposed to change this to “RAS-entity,” “RAS-entity in coordination with all RAS-owners” or “all RAS-owners shall jointly”.

Requirement R6, as written, suggests that independent analyses should be performed by each RAS-owner. It is proposed to change this to “RAS-entity,” “RAS-entity in coordination with all RAS-owners” or “all RAS-owners shall jointly”.

Requirement R7, as written, suggests that independent Corrective Action Plans should be submitted by each RAS-owner. It is proposed to change it to “RAS-entity”, “RAS-entity in coordination with all RAS-owners” or “All RAS-owners shall jointly”.

Requirement R9 stipulates that “At least once every six calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components.” An overall test includes Protection System components, as well as non-Protection System components, and operating any system equipment. Is this the intent of the Requirement?

Document Name:

Likes: 0

Dislikes:	0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

FMPA agrees with comments submitted by FRCC Reliability Coordinator.

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Requirement R1 is redundant with TPL standards. Since a RAS is installed to address reliability issues, it is, in essence, also installed to address performance requirements in planning studies. Thus, installation will have already been studied and addressed in the TPL studies (see Part 2.7.1). Since the Planning Coordinator is the reliability entity that should be reviewing and approving RAS, there would be no additional need to include Requirement R1 to submit this data as the Reliability Coordinator can and should get the information from the Planning Coordinator.

We are concerned that the Rationale Box for R3 implies that the Reliability Coordinator should be approving the trade-offs between dependability and security made by the equipment owners. We disagree. The Reliability Coordinator should simply be aware of how the RAS operates and the associated risks of Misoperation so that they can model in their operational studies.

We are concerned that there are overlaps with the TPL standards. Some have been mentioned in other questions. We won't repeat those here. However, we are concerned that R4 is redundant. Wouldn't the TP already be required to perform an evaluation of each RAS in the TPL standards since they have to consider RAS explicitly? TPL-001-4 Part 2.7.4 requires the "continued validity" of CAPs developed to address meeting performance requirements of the TPL standards to be reviewed annually. Since CAPs can include installation of RAS, this implies that study will be performed annually by the PC and TP to verify the RAS.

Part 4.3 should not reference the TPL standards. The performance requirements of the TPL standards stand alone and will be met. There is no need to reference them in this standard and potentially create redundancy and double jeopardy issues.

The measures need significant improvement as they are very generic. In general, they provide no more detail or guidance on how to demonstrate or measure compliance with the requirement. They primarily state that the applicable entity should have dated and time-stamped documentation which is basic requirement for any evidence. This is generic enough that a single generic measurement could be written to replace them.

Document Name:	
Likes:	0
Dislikes:	0

Chris Scanlon - Exelon - 1 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:

Answer Comment:

Hydro One Networks Inc.:

1)RAS are required for the reliability of the power system and compliance with the NERC reliability standards. As such, it is not the RAS owner who would decide on the need for a new or modified RAS and its functional specification. Instead, it is the TP who determines if a new RAS is needed or a RAS needs to be modified to meet the TPL-001-4 or other requirements. Just as R4 of PRC-012-2 requires “Each Transmission Planner shall perform an evaluation of each RAS within its planning area at least once every 60 full calendar months", it is only logical that before adding a new RAS or modifying an existing RAS, the TP should perform an evaluation and determine its functional specification. This must be the first requirement in PRC-012-2, similar to R1 of PRC-010-1/2.

2)The RAS owners design and engineer the RAS to meet the functional requirements specified by the TP.

3)Then R1 (which becomes R2) should ask the TP who has done the evaluation of new or modified RAS (not the RAS owner) to provide the information to RC, unless the TP and RC functions are performed by the same organization. TP has the information in Part II of the checklist in Attachment 1. Part III is the information that RAS owner can provide to TP or to RC.

Document Name:		
Likes:	1	Hydro One Networks, Inc., 1, Farahbakhsh Payam
Dislikes:	0	

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:

Answer Comment: None

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:

Answer Comment:

The scope of PRC-012-2 should be limited to cover RAS that are needed to meet the performance requirements of Table 1 in TPL-001-4 for disturbances in category P1 through P7 in order to remove extreme disturbances from the scope of the standard.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Texas RE is concerned there is there is a reliability gap in the determination of UVLS and its relationship to several standards projects including this one. In Project 2008-02.2 UVLS there is indication in the technical guide that certain UVLS will not be in a UVLS Program but would be considered a RAS yet the definition of RAS may exclude those UVLS systems. Texas RE acknowledges the need for flexibility, however, too much flexibility could cause reliability gaps that are supported by the language of the standards.

It appears in several projects many UVLS relays will now not be analyzed for misoperations (PRC-004-5), will not be in a UVLS Program (PRC-010), will not be considered a RAS (PRC-012-2) and will not be maintained per PRC-005. Texas RE requests the SDTs review these projects and determine the impacts thereof.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

Hydro One Networks Inc.:

1)RAS are required for the reliability of the power system and compliance with the NERC reliability standards.   As such, it is not the

RAS owner who would decide on the need for a new or modified RAS and its functional specification. Instead, it is the TP who determines if a new RAS is needed or a RAS needs to be modified to meet the TPL-001-4 or other requirements. Just as R4 of PRC-012-2 requires “Each Transmission Planner shall perform an evaluation of each RAS within its planning area at least once every 60 full calendar months”, it is only logical that before adding a new RAS or modifying an existing RAS, the TP should perform an evaluation and determine its functional specification. This must be the first requirement in PRC-012-2, similar to R1 of PRC-010-1/2.

2)The RAS owners design and engineer the RAS to meet the functional requirements specified by the TP.

3)Then R1 (which becomes R2) should ask the TP who has done the evaluation of new or modified RAS (not the RAS owner) to provide the information to RC, unless the TP and RC functions are performed by the same organization. TP has the information in Part II of the checklist in Attachment 1. Part III is the information that RAS owner can provide to TP or to RC.

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

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Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Daniela Hammons - CenterPoint Energy Houston Electric, LLC - 1 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer:

Answer Comment:

Tacoma Power recommends that the definition of 'RAS-owner' be limited to functional ownership, as opposed to component ownership. For example, if one company owns a station DC supply, some wiring, and trip coil, but another company owns the control device at the same location, the entity that owns the control device should be a RAS-owner, and the entity that owns the station DC supply, wiring, and trip coil should not be a RAS-owner. Another example would be an entity that owns sensing devices that another entity uses to provide inputs to a relay or PLC that it owns; the entity that owns the sensing devices in this example should not be a RAS-owner. Yet another example is when one entity owns a portion of the communications system; simply owning part of the communications system should not make the entity a RAS-owner.

Under Requirements R5, R6, R7, and R9, responsibility should be that of the RAS-entity, not the RAS-owner(s). Yes, RAS-owners may participate in fulfilling these requirements, but the RAS-entity should be the liaison. This proposed change may necessitate an additional requirement for RAS-owners to designate one RAS-entity for each RAS; in the event that consensus cannot be obtained among RAS-owners, the Reliability Coordinator should designate the RAS-entity.

Examples of what is and is not a functional modification would be beneficial.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

None.

Document Name:

Likes: 0

Dislikes: 0

Rico Garcillano - Pacific Gas and Electric Company - NA - Not Applicable - WECC

Selected Answer:

Answer Comment:

More clarity needs to be provided in terms of what counts as a functional modification as it is too subjective right now.

An example is if a line which is currently monitored as an outage for a scheme is bisected by a new looped sub, the scheme would be modified to monitor the two "new" lines created by new sub.

The conservative approach would be to submit for review and present the changes. But I would argue that if the load/gen is minimal, and the RAS actions are unchanged, a presentation and detailed review is not needed. If the RAS actions change as a result of the new sub, then I can see a review being required. Additionally, if a changes in the RAS actions are to take additional actions already part of the scheme, a less detailed reviewed could be required; vice versa, if new RAS actions are required, a more detailed review may be needed.

It may seem trivial, but with the amount of Capital investment going into our Transmission System right now, presenting every minor change that truly doesn't modify the functionality of a scheme would be a huge strain on resources.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Attachment 2
Reliability Coordinator RAS Review Checklist

The following checklist identifies ~~important~~ [JSW1]reliability-~~-~~related considerations for the Reliability Coordinator (RC) to review and verify for each new or functionally modified[2] RAS. The RC review is not limited to the RAS checklist items and the RC may request additional information on any reliability issue related to the RAS.

Determination of Review Level

RAS can have varying impacts on the power System. ~~RAS with more significant impact~~ [WTL2]~~require a higher level of review than those having a lesser impact.~~ [JSW3]The RC will determine t~~T~~he level of review ~~by the RC may be limited if~~based on ~~-~~the System response for a failure of the RAS to operate or if the inadvertent operation of the RAS could ~~not~~ result in any of the following conditions:

- frequency-related instability
- unplanned tripping of load or generation
- uncontrolled separation or ~~c~~Cascading[JSW4] ~~outages~~

If there is the potential for any of the conditions above to occur ~~may be produced~~, the ~~entire~~ RC RAS review checklist should include ~~below should be followed.~~ the RAS Design~~following~~ criteria below.~~:~~

~~RAS retirement reviews may use an abbreviated format that concentrates on the Planning justifications describing why the RAS is no longer needed. Implementation issues will seldom require removal review.~~[JSW5]

RAS DESIGN

- ❑ ~~System~~ **Performance Objectives** – ~~–~~ The ~~The~~ RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to mitigate.

- ❑ **Arming Conditions** - The RAS arming conditions, if applicable, are appropriate to its System performance objectives.

- ❑ **Adverse Interactions** – The ~~– The~~ RAS avoids adverse interactions with other RAS, P~~p~~rotection S~~s~~ystem[JSW6](s), control system(s), and O~~o~~perating P~~p~~rocedure[JSW7](s).

- ❑ **Misoperations** – The effects of RAS incorrect operation, including inadvertent operation and failure to operate (if non-operation for RAS single component failure is acceptable), have been identified.

    - The inadvertent operation of the RAS satisfies the same performance requirements as those required for the contingency for which it was designed. For RAS that are installed for conditions or contingencies for which there are no applicable System performance requirements, the inadvertent operation satisfies the System performance requirements of Table 1, Category P7 of NERC Reliability Standard TPL-

001-4 or its successor.

- **Future Plans** – The effects of future System plans on the design and operation of the RAS, where applicable, have been identified.

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[2] Functionally Modified:
Any modification to a RAS beyond the replacement of components that preserve the original functionality is a functional modification.

- ~~The effects of future System plans on the design and operation of the RAS, where applicable, have been identified.~~

RAS IMPLEMENTATION

- **RAS Logic** – The ~~c – The~~ implementation of RAS logic appropriately correlates desired actions (outputs) with System events and conditions (inputs).
- **Appropriate Timing** ~~–~~ – The ~~The~~ timing of RAS action(s) is appropriate to its System performance objectives.
- **Single Failure Expectations** – A ~~A~~ single component failure in a RAS does not prevent the BES from meeting the same performance requirements as those required for the System events and conditions for which the RAS was designed.
- **Testing and Maintenance** ~~–~~ – The ~~The~~ RAS design facilitates periodic testing and maintenance.
- **RAS Arming** ~~–~~ – The ~~The~~ mechanism or procedure by which the RAS is armed is clearly described, and is appropriate for reliable arming and operation of the RAS for the System conditions and events for which it is designed to operate.
- **Redundancy** – RAS ~~– RAS~~ automatic arming, if applicable, has the same degree of redundancy as the RAS itself.

RAS retirement reviews may use an abbreviated format that concentrates on the Planning justifications describing why the RAS is no longer needed. Implementation issues will seldom require removal review.

ERCOT Nodal Operating Guides

11.2 Special Protection System

(1) Special Protection Systems (SPSs) are protective relay systems designed to detect abnormal ERCOT System conditions and take pre-planned corrective actions to maintain a secure system.

(2) In addition to the requirements in the Protocols and applicable North American Electric Reliability Corporation (NERC) Reliability Standards, SPSs shall also meet the following requirements:

(a) The SPS owner shall coordinate the design and implementation of the SPS with the owners and operators of Facilities included in the SPS, including but not limited to Generation Resources, Transmission Service Providers (TSPs) and Direct Current Ties (DC Ties);

(b) The SPS shall be automatically armed when appropriate;

(c) The SPS shall not operate unnecessarily. To avoid unnecessary SPS operation, the SPS owner may provide a Real-Time status indication to the owner of any Generation Resource controlled by the SPS to show when the flow on one or more of the SPS monitored Facilities exceeds 90% of the flow necessary to arm the SPS. The cost necessary to provide such status indication shall be the responsibility of the SPS owner;

(d) The status indication of any automatic or manual arming/activation or operation of the SPS shall be provided as Supervisory Control and Data Acquisition (SCADA) alarm inputs to the owners of any Facility controlled by the SPS;

(e) When an SPS is removed from service, the SPS owner or its Designated Agent shall immediately notify ERCOT;

(f) When an SPS is returned to service, the SPS owner or its Designated Agent shall immediately notify ERCOT. ERCOT shall modify its reliability constraints to recognize the availability of the SPS;

(g) The SPS owner shall telemeter the status indication of the following items by SCADA to ERCOT for incorporation into ERCOT systems:

(i) Any automatic or manual arming/activation or operation of the SPS;

(ii) The in-service/out-of-service status of the SPS; and

(iii) Any additional related telemetry that already exists pertinent to the monitoring of the SPS (e.g. status indication of communications links between associated SPS equipment and the owner’s control center, arming limits of associated SPS equipment).

(h) The TSP may receive telemetry for a Resource Entity owned SPS through ERCOT or through the SPS owner, at the option of the TSP. The SPS owner, at its own cost, must provide telemetry for Resource Entity owned SPSs to the TSP upon request.

(4) The owners of an existing, modified, or proposed SPS shall submit documentation of the SPS to ERCOT for review and compilation into an ERCOT SPS database. The documentation shall detail the design, operation, functional testing, and coordination of the SPS with other protection and control systems.

(a) ERCOT shall conduct a review of each proposed SPS and each proposed modification to an existing SPS. Additionally, it shall conduct a review of each existing SPS at least every five years as required by changes in system conditions. Each review shall proceed according to a process and timetable documented in ERCOT Procedures and shall be posted on the Market Information System (MIS) Secure Area.

(b) The review of a proposed SPS shall be completed before the SPS is placed in service, unless ERCOT specifically determines that exemption of the proposed SPS from the review completion requirement is warranted. The timing of placing the SPS into service must be coordinated with and approved by ERCOT. The implementation schedule must be confirmed through submission of a Network Operations Model Change Request (NOMCR) to ERCOT.

(c) Existing SPSs that have already undergone at least one review shall remain in service during any subsequent review. Modifications to existing SPSs may be implemented upon approval by ERCOT.

(d) The process and schedule for placing an SPS into service must be consistent with documented ERCOT Procedures. The schedule must be coordinated among ERCOT and the owners of the Facility controlled by the SPS, and shall provide sufficient time to perform any necessary testing prior to its being placed in service.

(e) ERCOT review of an SPS shall:

(i) Identify any conflicts with the Protocols, NERC Reliability Standards, and these Operating Guides;

(ii) Evaluate and document the consequences of failure of a single component of the SPS, which would result in failure of the SPS to operate when required; and

(iii) Evaluate and document the consequences of misoperation, incorrect operation, or unintended operation of an SPS, when considered by itself and without any other system contingency.

(iv) Upon completion of ERCOT's SPS review, ERCOT shall provide all results and underlying studies to the SPS owner.

(f) If deficiencies are identified by ERCOT or other parties' comments, the SPS owner shall either submit an amended SPS proposal or withdraw the SPS proposal. The amended SPS proposal shall undergo the review process specified in item (e) above until the identified deficiencies have been resolved to the satisfaction of ERCOT.

(g) As part of the ERCOT review, ERCOT shall notify the Steady State Working Group (SSWG), the Dynamics Working Group (DWG), and the System Protection Working Group (SPWG) of the SPS proposal, and each working group or any member of each working group may provide any comments, questions, or issues to ERCOT. ERCOT may work with the owner(s) of Facilities controlled by the SPS as necessary to address all issues.

(h) ERCOT shall develop a method to include the SPS in Security-Constrained Economic Dispatch (SCED), Outage coordination, and Reliability Unit Commitment (RUC).

(i) ERCOT's review shall provide an opportunity for and include consideration of comments submitted by Market Participants affected by the SPS.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

Draft 1 of PRC-012-2 corrects the applicability of the fill-in-the-blank standards (PRC-012-1, PRC-013-1, and PRC-014-1) by assigning the requirement responsibilities to the specific users, owners, and operators of the Bulk-Power System, and incorporates the reliability objectives of all the RAS/SPS-related standards. Draft 1 contains nine requirements and measures, the associated rationale boxes and corresponding technical guidelines. There are also three attachments within the draft standard that are incorporated via references in the requirements. Draft 1of PRC-012-2 is posted for a 45-day initial formal comment period with a parallel initial ballot in the last ten days of the comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	February 12, 2014
SAR posted for comment	February 18, 2014
Standards Committee approved the SAR	June 10, 2014
Draft 1 of PRC-012-2 posted for informal comment	April 30 – May 20, 2015
45-day formal comment period with initial ballot	August 20 – October 5, 2015

Anticipated Actions	Date
10-day final ballot	December 2015
NERC Board (Board) adoption	February 2016

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Remedial Action Schemes
2. **Number:** PRC-012-2
3. **Purpose:** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Transmission Planner
     - **4.1.3.** RAS-owner – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS
     - **4.1.4.** RAS-entity – the RAS-owner designated to represent all RAS-owner(s) for coordinating the review and approval of a RAS
   - **4.2. Facilities:**
     - **4.2.1.** Remedial Action Schemes (RAS)
5. **Effective Date:** See the Implementation Plan for PRC-012-2.

B. Requirements and Measures

Rationale for Requirement R1: Each Remedial Action Scheme (RAS) is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES). Therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification or retirement (removal from service) must be completed prior to implementation or retirement. A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality.

To facilitate a review that promotes reliability, the RAS-entity must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity provide them to the reviewing Reliability Coordinator (RC). The RC (reviewing RC) that coordinates the area where the RAS is located is responsible for the review. In cases where a RAS crosses one or more RC Area boundaries, each affected RC is responsible for conducting either individual reviews or a coordinated review.

R1. Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity shall submit the information identified in Attachment 1 for review to the Reliability Coordinator(s) that coordinates the area(s) where the RAS is located. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, a copy of the Attachment 1 documentation and the dated communications with the reviewing Reliability Coordinator(s) in accordance with Requirement R1.

Rationale for Requirement R2: The RC is the functional entity best suited to perform the RAS review because it has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in any neighboring RC Area. This Wide Area purview provides continuity in the review process and facilitates the evaluation of interactions among separate RAS as well as interactions among RAS and other protection and control systems. Including the RC also minimizes the possibility of a conflict of interest that could exist because of business relationships among the RAS-entity, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC may request assistance in RAS reviews from other parties such as the PC or regional technical groups; however, the RC will retain the responsibility for compliance with this requirement.

Attachment 2 of this standard is a checklist the RC can use to identify design and implementation aspects of RAS and facilitate consistent reviews for each RAS submitted. The time frame of four-full-calendar months is consistent with current utility and regional practice; however, flexibility is provided by allowing the parties to negotiate a mutually agreed upon schedule for the review.

Note: An RC may need to include this task in its reliability plan(s) for the NERC Regions(s) in which it is located.

R2. Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1, shall, within four-full-calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to the RAS-entity. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated reports, checklists, or other documentation detailing the RAS review, and the dated communications with the RAS-entity in accordance with Requirement R2.

Rationale for Requirement R3: The RC review is intended to identify reliability issues that must be resolved before the RAS can be put in service. Examples of reliability issues include a lack of dependability, security, or coordination.

A specific time period for the RAS-entity to respond to the RC review is not necessary because it is in the RAS-entity's interest to obtain an expeditious response from the entity and thus ensure a timely implementation.

R3. Following the review performed pursuant to Requirement R2, the RAS-entity shall address each identified issue and obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in service or retiring an existing RAS. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Acceptable evidence may include, but is not limited to, dated documentation and communications with the reviewing Reliability Coordinator in accordance with Requirement R3.

Rationale for Requirement R4: Requirement R4 mandates that an evaluation of each RAS be performed at least once every sixty-full-calendar months. The purpose of a periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that requirements for BES performance following an inadvertent RAS operation or a single component failure in the RAS continues to be satisfied. A periodic evaluation is needed because changes in system topology or operating conditions that have occurred since the previous RAS evaluation—or initial review—was completed may change the effectiveness of a RAS or the way it impacts the BES.

Sixty-full-calendar months, which begins on the effective date of the standard pursuant to the implementation plan, was selected as the maximum time frame between evaluations based on the time frames for similar requirements in Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation can be performed sooner if it is determined that material changes to system topology or system operating conditions have occurred that could potentially impact the effectiveness or coordination of the RAS. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluation are planning analyses that involve modeling of the interconnected transmission system to assess BES performance; consequently, the TP is the functional entity best suited to perform the analyses. To promote reliability, the TP is required to provide the RAS-owner(s) and each reviewing RC with the results of the evaluation.

The previous version of this standard (PRC-012-0 Requirement 1, R1.4) states "… 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." Requirement R4 clarifies that the inadvertent operation to be considered would only be that caused by the malfunction of a single RAS component. This allows security features to be designed into the RAS such that inadvertent operation due to a single component malfunction is prevented. Otherwise and consistent with PRC-012-0 Requirement 1, R1.4, the RAS should be designed so that its whole or partial inadvertent operation due to a single component malfunction satisfies the system 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 some other Contingency or System condition not defined in TPL-001-4 (therefore without performance requirements), its inadvertent operation still must meet some minimum System performance requirements. However, instead of referring to the TPL-001-4, Requirement R4 lists the System performance requirements that the inadvertent operation must satisfy. The performance requirements listed (Parts 4.3.1 – 4.3.5) are the ones that are common to all planning events P0-P7 listed in TPL-001-4.

R4. Each Transmission Planner shall perform an evaluation of each RAS within its planning area at least once every 60-full-calendar-months and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed.

4.2. The RAS avoids adverse interactions with other RAS, and protection and control systems.

4.3. The possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following:

4.3.1. The BES shall remain stable.

4.3.2. Cascading shall not occur.

4.3.3. Applicable Facility Ratings shall not be exceeded.

4.3.4. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

4.3.5. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

4.4. 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 is designed.

M4. Acceptable evidence may include, but is not limited to, dated reports or other documentation of the analyses comprising the evaluation(s) of each RAS and dated communications with the RAS-owner(s) and the reviewing Reliability Coordinator(s) in accordance with Requirement R4.

Rationale for Requirement R5: The correct operation of a RAS is important for maintaining the reliability and integrity of the BES. Any incorrect operation of a RAS indicates that the RAS effectiveness and/or coordination has been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: 1) verify RAS operation is consistent with the implemented design; or 2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120-calendar-day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation. To promote reliability, each RAS-owner is required to provide the results of RAS operational performance analyses to each reviewing RC.

RAS-owners may need to collaborate with their associated TP to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation triggers and responds (Parts 5.1, 5.2) and that the resulting BES response (Parts 5.3, 5.4) is consistent with the intended functionality and design of the RAS.

R5. Each RAS-owner shall, within 120-calendar days of a RAS operation or failure of a RAS to operate when expected, analyze the RAS performance and provide the results of the analysis, including any identified deficiencies, to its reviewing Reliability

Coordinator(s). The RAS operational performance analysis shall determine whether: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The System events and/or conditions appropriately triggered the RAS.

5.2. The RAS responded as designed.

5.3. The RAS was effective in mitigating BES performance issues it was designed to address.

5.4. The RAS operation resulted in any unintended or adverse BES response.

M5. Acceptable evidence may include, but is not limited to, dated documentation detailing the RAS operational performance analysis in accordance with Requirement R5.

Rationale for Requirement R6: Deficiencies, identified either in the periodic RAS evaluation conducted by the TP in Requirement R4 or in the analysis conducted by the RAS-owner pursuant to Requirement R5, are likely to pose a reliability risk to the BES. To mitigate potential reliability risks, Requirement R6 mandates that the RAS-owner develop a Corrective Action Plan (CAP) that establishes the mitigation actions and timetable to address the deficiency. If the CAP requires that a functional change be made to a RAS, the RAS-owner will need to submit information identified in Attachment 1 to the reviewing RC(s) prior to placing RAS modifications in service per Requirement R1.

Depending on the complexity of the issues, development of a CAP might require study, engineering, or consulting work. A time frame of six-full-calendar months is specified to allow enough time for RAS-owner collaboration on the CAP development, while ensuring that deficiencies are addressed in a reasonable time.

R6. Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

M6. Acceptable evidence may include, but is not limited to, a dated CAP and dated communications with each reviewing Reliability Coordinator in accordance with Requirement R6.

Rationale for Requirement R7: Requirement R7 mandates the RAS-owner(s) implement a CAP (developed in Requirement R6) that mitigates the deficiencies identified in Requirements R4 and R5. By definition, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem." The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. Each reviewing Reliability Coordinator must be notified if CAP actions or timetables change.

R7. For each CAP submitted pursuant to Requirement R6, each RAS-owner shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

7.1. Implement the CAP.

7.2. Update the CAP if actions or timetables change.

7.3. Notify each reviewing Reliability Coordinator if CAP actions or timetables change.

M7. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, and communication with the appropriate Reliability Coordinator(s) that documents the implementation or updating of a CAP in accordance with Requirement R7.

Rationale for Requirement R8: Due to the wide variety of RAS designs and implementations, and the potential for impacting BES reliability, it is important that periodic functional testing of a RAS be performed. A functional test provides an overall confirmation of the RAS to operate as designed and verifies the proper operation of the non-Protection System (control) components of a RAS that are not addressed in PRC-005. Protection System components that are part of a RAS are maintained in accordance with PRC-005. The drafting team selected a six-calendar-year testing interval to be consistent with some of the maintenance intervals of various Protection System and Automatic Reclosing components established in PRC-005. This interval provides an entity the opportunity to design its RAS functional testing program such that it coincides with the testing of any associated PRC-005 components.

The six-calendar-year interval, which begins on the effective date of the standard pursuant to the implementation plan, is a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS. Extending to longer intervals increases the reliability risk to the BES posed by a potentially undiscovered latent failure that could cause an incorrect operation of the RAS. The RAS-owner is in the best position to determine the testing procedure and schedule due to its overall knowledge of the RAS design, installation, and functionality. Functional testing may be accomplished with end-to-end testing or a segmented approach. Each segment of a RAS should be tested but overlapping segments can be tested individually negating the need for complex maintenance schedules and outages. A correct operation of a RAS qualifies as a functional test as long as all segments operate. If an event causes a partial operation of a RAS, the segments without an operation will require a functional test within the six year interval to be compliant with Requirement R8.

R8. At least once every six-calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-

Protection System components. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M8. Acceptable evidence may include, but is not limited to, dated documentation of the functional testing in accordance with Requirement R8.

Rationale for Requirement R9: The RAS database is a comprehensive record of all RAS existing in a Reliability Coordinator Area. The database enables the RC to provide other entities high-level information on existing RAS that can potentially impact the entities' operational and/or planning activities. Attachment 3 lists the minimum information required for the RAS database, which includes a summary of the RAS initiating conditions, corrective actions, and System issues being mitigated. This information allows an entity to evaluate the reliability need for requesting more detailed information from the RAS-entity identified in the database contact information. The RC is the appropriate entity to maintain the database because the RC receives the required database information when a new or modified RAS is submitted for review.

R9. Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once each calendar year. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M9. Acceptable evidence may include, but is not limited to, dated spreadsheets, database reports, or other documentation demonstrating a RAS database was maintained in accordance with Requirement R9.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance with Requirements R1 through R9, and Measures M1 through M9 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The RAS-entity failed to submit the information identified in Attachment 1 to one or more of the Reliability Coordinator(s) in accordance with Requirement R1.
R2.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30-calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30-calendar days but less than or equal to 60-calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 60-calendar days but less than or equal to 90-calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90-calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in accordance with Requirement R2.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	N/A	N/A	N/A	The RAS-entity failed to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in service or retiring an existing RAS in accordance with Requirement R3.
R4.	The Transmission Planner performed the evaluation in accordance with Requirement R4, but in greater than 60-full-calendar months but less than 61-full-calendar months.	The Transmission Planner performed the evaluation in accordance with Requirement R4, but in greater than 61-full-calendar months but less than 62-full-calendar months.	The Transmission Planner performed the evaluation in accordance with Requirement R4, but in greater than 62-full-calendar months but less than 63-full-calendar months. OR The Transmission Planner performed the evaluation in accordance with Requirement R4, but failed to evaluate one of the Parts 4.1 through 4.4.	The Transmission Planner performed the evaluation in accordance with Requirement R4, but in greater than 63-full-calendar months. OR The Transmission Planner failed to perform the evaluation in accordance with Requirement R4. OR The Transmission Planner performed the evaluation in accordance with Requirement R4, but failed

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				to evaluate two or more of the Parts 4.1 through 4.4. OR The Transmission Planner performed the evaluation in accordance with Requirement R4, but failed to provide the results to one or more of the RAS-owner(s) and the reviewing Reliability Coordinator(s).
R5.	The RAS-owner performed the analysis in greater than 120-calendar days, but less than or equal to 130-calendar days in accordance with Requirement R5.	The RAS-owner performed the analysis in greater than 130-calendar days, but less than or equal to 140-calendar days in accordance with Requirement R5.	The RAS-owner performed the analysis in greater than 140-calendar days, but less than or equal to 150-calendar days in accordance with Requirement R5. OR The RAS-owner performed the analysis in accordance with Requirement R5, but failed to address one of the Parts 5.1 through 5.4.	The RAS-owner performed the analysis in greater than 150-calendar days. OR The RAS-owner failed to perform the analysis in accordance with Requirement R5. OR The RAS-owner performed the analysis in accordance with Requirement R5, but failed to address two or

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				more of the Parts 5.1 through 5.4. OR The RAS-owner performed the analysis in accordance with Requirement R5, but failed to provide the results to one or more of the reviewing Reliability Coordinator(s).
R6.	The RAS-owner developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10-calendar days.	The RAS-owner developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10-calendar days but less than or equal to 20-calendar days.	The RAS-owner developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20-calendar days but less than or equal to 30-calendar days.	The RAS-owner developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30-calendar days. OR The RAS-owner developed a Corrective Action Plan and failed to submit it to one or more of its reviewing Reliability Coordinator(s) in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				accordance with Requirement R6. OR The RAS-owner failed to develop a Corrective Action Plan in accordance with Requirement R6.
R7.	The RAS-owner implemented a CAP (Part 7.1), but failed to update the CAP (Part 7.2) if actions or timetables changed and failed to notify one or more of the reviewing Reliability Coordinator(s) (Part 7.3), in accordance with Requirement R7.	N/A	N/A	The RAS-owner failed to implement a CAP (Part 7.1) in accordance with Requirement R7.
R8.	The RAS-owner performed the functional test for a RAS as specified in Requirement R8, but was less than or equal to 30-calendar days late.	The RAS-owner performed the functional test for a RAS as specified in Requirement R8, but was more than 30-calendar days but less than or equal to 60-calendar days late.	The RAS-owner performed the functional test for a RAS as specified in Requirement R8, but was more than 60-calendar days but less than or equal to 90-calendar days late.	The RAS-owner performed the functional test for a RAS as specified in Requirement R8, but was more than 90-calendar days late. OR The RAS-owner failed to perform the functional test

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				for a RAS as specified in Requirement R8.
R9.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30-calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30-calendar days but less than or equal to 60-calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60-calendar days but less than or equal to 90-calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90-calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

D. Regional Variances

None.

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
1		Adopted by NERC Board of Trustees	New

Attachment 1
Supporting Documentation for RAS Review

The following checklist identifies important Remedial Action Scheme (RAS) information for each new or functionally modified[1] RAS that the RAS-entity shall document and provide to the reviewing Reliability Coordinator(s) (RC) for review. If an item on this list does not apply to a specific RAS, a response of N/A or Not Applicable for that item is appropriate. When a RAS has been previously reviewed, only the proposed modifications to that RAS require review; however, the RAS-entity must provide a summary of the previously approved functionality. The RC may request additional information on any reliability issue related to the RAS. Additional entities (without decision authority) may be part of the RAS review process at the request of the RC.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.
2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.
3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP. [Reference NERC Reliability Standard PRC-012, Requirements R5 and R7]
4. Data to populate the RAS database:
    a. RAS name.
    b. RAS-entity and contact information.
    c. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
    d. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
    e. Description of the contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
    f. Action(s) to be taken by the RAS.
    g. Any additional explanation relevant to high-level understanding of the RAS.

[1] Functionally Modified: Any modification to a RAS beyond the replacement of components that preserve the original functionality is a functional modification.

II. Functional Description and Transmission Planning Information

1. Contingencies and System conditions that the RAS is intended to remedy. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.1]
2. The action(s) to be taken by the RAS in response to disturbance conditions. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.2]
3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and the date those technical studies were performed. [Reference NERC Reliability Standard PRC-014, R3.2]
4. Information regarding any future System plans that will impact the RAS. [Reference NERC Reliability Standard PRC-014, R3.2]

   Documentation showing that the possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following: [Reference NERC Reliability Standard PRC-012, R1.4]

   a. The BES shall remain stable.

   b. Cascading shall not occur.

   c. Applicable Facility Ratings shall not be exceeded.

   d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

   e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.
5. An evaluation indicating that the RAS settings and operation avoid adverse interactions with other RAS, and protection and control systems. [Reference NERC Reliability Standards PRC-012, R1.5 and PRC-014, R3.4]
6. Identification of other affected RCs.

III. Implementation

1. Documentation describing the applicable equipment used for detection, telecommunications, transfer trip, logic processing, and monitoring.
2. Information on detection logic and settings/parameters that control the operation of the RAS. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.3]
3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in service or is being maintained.

4. Documentation showing that 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 is designed. The documentation should describe or illustrate how the design achieves this objective. [Reference NERC Reliability Standard PRC-012, R1.3]
5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies RAS information that the RAS-entity shall document and provide to each reviewing RC.

1. Information necessary to ensure that the RC is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of applicable technical studies and technical justifications upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

Attachment 2
Reliability Coordinator RAS Review Checklist

The following checklist identifies reliability-related considerations for the Reliability Coordinator (RC) to review and verify for each new or functionally modified[2] Remedial Action Scheme (RAS). The RC review is not limited to the checklist items and the RC may request additional information on any reliability issue related to the RAS.

I. Design

1. The RAS actions satisfy performance objectives for the scope of events and conditions that the RAS is intended to mitigate.
2. The RAS arming conditions, if applicable, are appropriate to its System performance objectives.
3. The RAS avoids adverse interactions with other RAS, and protection and control systems.
4. The effects of RAS incorrect operation, including inadvertent operation and failure to operate (if non-operation for RAS single component failure is acceptable), have been identified.
5. The possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following:
    a. The BES shall remain stable.
    b. Cascading shall not occur.
    c. Applicable Facility Ratings shall not be exceeded.
    d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.
    e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.
6. The effects of future BES modifications on the design and operation of the RAS have been identified, where applicable.

II. Implementation

1. The implementation of RAS logic appropriately correlates desired actions (outputs) with events and conditions (inputs).
2. The timing of RAS action(s) is appropriate to its BES performance objectives.

[2] Functionally Modified:
Any modification to a RAS beyond the replacement of components that preserve the original functionality is a functional modification.

3. A single component failure in a RAS does not prevent the BES from meeting the same performance requirements as those required for the events and conditions for which the RAS is designed.
4. The RAS design facilitates periodic testing and maintenance.
5. The mechanism or procedure by which the RAS is armed is clearly described, and is appropriate for reliable arming and operation of the RAS for the conditions and events for which it is designed to operate.

III. RAS Retirement

RAS retirement reviews should assure that there is adequate justification for why a RAS is no longer needed.

Attachment 3
Database Information

1. RAS name.
2. RAS-entity and contact information.
3. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
5. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
6. Action(s) to be taken by the RAS.
7. Any additional explanation relevant to high-level understanding of the RAS.

Technical Justifications for Requirements

Applicability

4.1.4 RAS-entity

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

If the RAS equipment has more than one owner, then each separate RAS equipment owner is a RAS-owner. The RAS-entity will always be one of these RAS-owners. A RAS-entity will be selected by all RAS-owners and, traditionally, has usually been the owner of the RAS controller and a Transmission Owner. If a specific RAS-entity is not identified by the RAS-owners, the RC will assign that function to the RAS-owner who provides the review material to them.

The RAS-owner(s); i.e., Transmission Owner(s), Generator Owner(s), or Distribution Provider(s) who are not the RAS-entity still have responsibilities as assigned in other NERC Reliability Standards, such as equipment maintenance. In addition, when RAS modifications are needed, each RAS-owner of RAS equipment that must be modified must accept the specific responsibilities assigned to them as described in the necessary Corrective Action Plan (CAP), or otherwise as described in the revised Attachment 1.

Requirement R1

Each RAS is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES); therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification, or retirement (removal from service) must be completed prior to implementation.

Any modification to RAS hardware beyond the substitution of components that merely preserve the original functionality is a functional modification. Any change in RAS logic such as new inputs or outputs, or any other modification that affects overall RAS functionality, or redundancy level as documented in the original submission for review are functional modifications. RAS modifications identified by a CAP pursuant to Requirement R6 beyond the substitution of components that merely preserve the original functionality are functional modifications. RAS removal is essentially a form of RAS functional modification. Any RAS proposed for removal needs to be evaluated under the RAS Retirement section of the Attachment 1 checklist.

To facilitate a review that promotes reliability, the RAS-entity must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity provide them to the reviewing Reliability Coordinator (RC). The RC that coordinates the area where the RAS is located is responsible for the review. In cases where a RAS crosses multiple RC Area boundaries, each affected RC is responsible for conducting either individual reviews or a coordinated review.

Requirement R1 does not specify how far in advance of implementation the RAS-entity must provide Attachment 1 data to the reviewing RC. The information will need to be submitted early enough to allow RC review in the allotted time pursuant to Requirement R2, including resolution of any issues that might be identified, in order to obtain approval of the reviewing RC. Expeditious submittal of this information is in the interest of each RAS-owner to effect a timely implementation.

Requirement R2

Requirement R2 mandates that the RC perform reviews of all proposed new RAS and existing RAS proposed for functional modification, or retirement (removal from service) in its RC Area.

RAS are unique and customized assemblages of protection and control equipment. As such, they have a potential to introduce reliability risks to the BES, if not carefully planned, designed, and installed. A RAS may be installed to address a reliability issue, or achieve an economic or operational advantage, and could introduce reliability risks that might not be apparent to a RAS-owner(s). An independent review by a multi-disciplinary panel of subject matter experts with planning, operations, protection, telecommunications, and equipment expertise is an effective means of identifying risks and recommending RAS modifications when necessary.

The RC is the functional entity best suited to perform the RAS reviews because it 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 facilitates the evaluation of interactions among separate RAS as well as interactions among the 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, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC may request assistance in RAS reviews from other parties such as the PC(s) or regional technical groups (e.g., Regional Entities); however, the RC retains responsibility for compliance with the requirement.

Attachment 2 of this standard is a checklist for assisting the RC in identifying design and implementation aspects of a RAS, and for facilitating consistent reviews of each submitted RAS for review. The time frame of four-full-calendar months is consistent with current utility practice; however, flexibility is provided by allowing the parties to negotiate a different schedule for the review. Note, an RC may need to include this task in its reliability plan(s) for the NERC Region(s) in which it is located.

Requirement R3

Requirement R3 mandates that the RAS-entity address all issues identified by the reviewing RC during the RAS review, and obtain approval from the reviewing RC that the RAS implementation can proceed. The review by the RC is intended to identify reliability issues that must be resolved before the RAS can be put in service. Examples of reliability issues include a lack of dependability, security, or coordination.

Dependability is a component of reliability and is the measure of certainty of a device to operate when required. If a RAS is installed to meet performance requirements of NERC Reliability Standards, a failure of the RAS to operate when intended would put the System at risk of violating NERC Reliability Standards if specified Contingency(ies) or System conditions occur. This risk is mitigated by designing the RAS so that it will accomplish the intended purpose while experiencing a single RAS component failure. This is often accomplished through redundancy. Other strategies for providing dependability include “over-tripping” load or generation, or alternative automatic backup schemes.

Security is a component of reliability and is the measure of certainty of a device to not operate inadvertently. False or inadvertent operation of a RAS results in taking a programmed action without the appropriate arming conditions, occurrence of specified Contingency(ies), or System conditions expected to trigger the RAS action. Typical RAS actions include shedding load or generation or re-configuring the System. Such actions, if inadvertently taken, are undesirable and may put the System in a less secure state. Worst case impacts from inadvertent operation often occur if all programmed RAS actions occur. If the System performance still satisfies PRC-012-2 Requirement R4, Part 4.3, no additional mitigation is required. Security enhancements to the RAS design, such as voting schemes, are acceptable mitigations against inadvertent operations.

Any reliability issue identified during the review must be resolved before implementing the RAS to avoid placing the System at unacceptable risk. The RAS-entity (and any other RAS-owner) or the reviewing RC(s) may have alternative ideas or methods available to resolve the issue(s). In either case, the concern needs to be resolved in deference to reliability, and the RC has the final decision.

A specific time period for the RAS-entity to respond to the RC(s) review is not necessary because an expeditious response is in the interest of each RAS-owner to effect a timely implementation.

Requirement R4

Requirement R4 mandates that an evaluation of each RAS be performed at least once every 60-full-calendar months. The purpose of a periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that requirements for BES performance following inadvertent RAS operation and single component failure continue to be satisfied. A periodic evaluation is required because changes in system topology or operating conditions that have occurred since the previous RAS evaluation (or initial review) may change the effectiveness of a RAS or the way it interacts with and impacts the BES.

A period of sixty-full-calendar months was selected as the maximum time frame between evaluations based on similar requirements in NERC Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation should be performed sooner if it is determined that material changes to System topology or System operating conditions that could potentially impact the effectiveness or coordination of the RAS have occurred since the previous RAS evaluation or will occur before the next scheduled evaluation. The periodic RAS evaluation will lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or 3) justification for RAS retirement.

The items required to be addressed in the evaluations (Requirement R4, Parts 4.1 through 4.4) are planning analyses that involve modeling of the interconnected transmission system to assess BES performance; consequently, the TP is the functional entity best suited to perform the analyses. To promote reliability, the TP is required to provide the RAS-owner(s) and the reviewing RC(s) with the results of each evaluation.

The intent of Requirement R4, Part 4.3 is to require that the possible inadvertent operation of the RAS, caused by the malfunction of a single component of the RAS, meet the same System performance requirements as those required for the Contingency(ies) or System conditions for which it is designed. If the RAS is designed to meet one of the planning events (P0-P7) in TPL-001-4, the possible inadvertent operation of the RAS must meet the same performance requirements listed in the standard for that planning event. The requirement clarifies that the inadvertent operation to be considered is only that caused by the malfunction of a single RAS component. This allows features to be designed into the RAS to improve security, such that inadvertent operation due to malfunction of a single component is prevented or else the RAS inadvertent operation satisfies Requirement R4, Part 4.3.

The intent of Requirement R4, Part 4.3 is also to require that the possible inadvertent operation of the RAS installed for an extreme event in TPL-001-4 or for some other Contingency or System conditions not defined in TPL-001-4 (therefore without performance requirements), meet the minimum System performance requirements of Category P7 in Table 1 of NERC Reliability Standard TPL-001-4. However, instead of referring to the TPL standard, the requirement lists the System performance requirements that a potential inadvertent operation must satisfy. The performance requirements listed (Requirement R4, Parts 4.3.1 – 4.3.5) are the ones that are common to all planning events P0-P7 listed in TPL-001-4.

With reference to Requirement 4, Part 4.3, note that the only differences in performance requirements among the TPL P0-P7 events (not common to all of them) concern Non-Consequential Load Loss and interruption of Firm Transmission Service. Performance requirements in these areas are not relevant. A RAS is only allowed to drop non-consequential load or interrupt Firm Transmission Service can do that only if that action is allowed for the Contingency for which it is designed. Therefore, the inadvertent operation should automatically meet Non-Consequential Load Loss or interrupting Firm Transmission Service performance requirements for the Contingency(ies) for which it was designed.

Part 4.4 requires that 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 is designed. This analysis is needed to ensure that changing System conditions do not result in the single component failure requirement not being met.

Requirements for inadvertent RAS operation (Requirement R4, Part 4.3) and single component failure (Requirement R4, Part 4.4) are reviewed by the reviewing RC(s) before a new or functionally modified RAS is placed in service, and are typically satisfied by specific design considerations. Although the scope of the periodic evaluation does not include a new design review, it is possible that a design which previously satisfied requirements for inadvertent RAS operation and single component failure may fail to satisfy these requirements at a later point in time, and must be evaluated with respect to the current System. For example, if the actions of a particular RAS include tripping load, System changes could occur over time that impact the amount of load originally tripped by a particular RAS output. These changes could result in inadvertent activation of that output, therefore, tripping too much load and result in violations of Facility Ratings. Alternatively, the RAS might be designed to trip more load than necessary (i.e., "over trip") in order to satisfy single-component-failure requirements. System changes could result in too little load being tripped at affected locations and result in unacceptable BES performance if one of the loads failed to trip.

Requirement R5

The correct operation of a RAS is important to maintain the reliability and integrity of the BES. Any incorrect operation of a RAS indicates the RAS effectiveness and/or coordination may have been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: (1) verify RAS operation is consistent with implemented design; or (2) identify RAS performance deficiency(ies) that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120-calendar day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation. To promote reliability, the RAS-owner(s) is required to provide the results of RAS operational performance analyses to its reviewing RC(s).

The RAS-owner(s) may need to collaborate with their associated TP to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation triggers and responds (Parts 5.1, 5.2) and that the resulting BES response (Parts 5.3, 5.4) is consistent with the intended functionality and design of the RAS.

Requirement R6

Deficiencies identified either in the periodic RAS evaluation conducted by the TP in Requirement R4, or in the analysis conducted by the RAS-owner(s) pursuant to Requirement R5, are likely to pose a reliability risk to the BES. To mitigate this reliability risk, Requirement R6 mandates that each RAS-owner develop a CAP that establishes the mitigation actions and timetable to address the deficiency. If the CAP requires that a functional change be made to a RAS, Attachment 1 information must be submitted to the reviewing RC(s) prior to placing RAS modifications in service per Requirement R1.

Depending on the complexity of the issues, development of a CAP may require study, engineering, or consulting work. A timeframe of six-full-calendar months is allotted to allow enough time for RAS-owner collaboration on the CAP development, while ensuring that deficiencies are addressed in a reasonable time. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the RAS deficiency is resolved. Such operating restrictions will incent the RAS-owner to resolve the issue as quickly as possible.

A CAP documents a RAS performance deficiency, the actions to correct the deficiency with identified tasks, and the time frame for completion.

The following are example situations of when a CAP is required:

- A determination after a RAS operation/non-operation investigation that the RAS did not meet performance expectations. The RAS did not operate as designed.
- Periodic planning assessment reveals RAS changes are necessary to correct performance or coordination issues.
- Equipment failures.

Requirement R7

Implementation of a CAP ensures that RAS deficiencies are corrected by following a documented timetable of identified actions. If necessary, the CAP can be modified to account for adjustments to the actions or scheduled timetable of activities. Operating restrictions imposed by the RC also incents RAS-owners to mitigate the issues and provide assurance that implementation is completed in a timely manner.

Requirement R8

The reliability objective of Requirement R8 is to test the non-Protection System components of a RAS (controllers such as programmable logic controllers (PLCs)) and to verify the overall performance of the RAS through functional testing. Functional tests validate RAS operation by ensuring System states are detected and processed, and that actions taken by the controls are correct and within the expected time using the in-service settings and logic. Functional testing is aimed at assuring overall RAS performance and not the component focused testing contained in the PRC-005 maintenance standard.

Since the functional test operates the RAS under controlled conditions with known System states and expected results, testing and analysis can be performed without impact to the BES and should align with expected results. The RAS-owner is in the best position to determine the testing procedure and schedule due to their overall knowledge of the RAS design, installation, and functionality. Periodic testing provides the RAS-owner assurance that latent failures may be identified and also promotes identification of changes in the System that may have introduced latent failures.

While the six-calendar-year functional testing interval is greater than the annual or bi-annual periodic testing performed in some NERC Regions, the drafting team selected it because it is consistent with some of the maintenance intervals of various Protection System and Automatic Reclosing components established in PRC-005. Consequently, this interval provides entities the opportunity to design their RAS functional testing programs such that it coincides with the testing of any associated PRC-005 components. The six-calendar-year interval is a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS.

Functional testing is not synonymous with end-to-end testing. End-to-end testing is acceptable but it may not feasible for many RAS. When end-to-end testing is not possible, a RAS-owner may use a segmented functional testing approach. The segments can be tested individually negating the need for complex maintenance schedules. In addition, actual RAS operation(s) can be used to fulfill the functional testing requirement. If a RAS does not operate in its entirety during a System event or System conditions do not allow an end-to-end system test—the, the segmented approach should be used to fulfill this Requirement. Functional testing includes the testing of all RAS inputs used for detection, arming, operating, and data collection. Functional testing also includes the processing by the logic and infrastructure of a RAS as well as the action initiation by RAS outputs to address the System condition(s) for which the RAS is designed. All segments and components of a RAS must be tested or have proven operations within a six-calendar-year interval to demonstrate compliance with the Requirement.

As an example, consider a RAS implemented with one PLC that senses System conditions such as loading and line status from many locations. At one of these locations, a line protective relay (a component of a Protection System and included in the Protection System Maintenance Program (PSMP) of a RAS-owner) receives commands from the RAS PLC and sends data over non-Protection System communications infrastructure to operate a breaker. A functional test would send signals of simulated System conditions to the PLC to initiate an operate command to the protective relay, thus operating its associated breaker. This action verifies RAS action, verifies PLC control logic, and verifies RAS communications from PLC to relay. To complete this portion of a functional test, application of external testing signals to the protective relay, verified at the PLC are necessary to confirm full functioning of the RAS segment being tested. This example describes a test for one segment of the RAS, the remaining segments would also require testing.

IEEE C37.233, "IEEE Guide for Power System Protection Testing," 2009 section 8 (particularly 8.3-8.5), provides an overview of functional testing. The following opens section 8.3:

> Proper implementation requires a well-defined and coordinated test plan for performance evaluation of the overall system during agreed maintenance intervals. The maintenance test plan, also referred to as functional system testing, should include inputs, outputs, communication, logic, and throughput timing tests. The functional tests are generally not component-level testing, rather overall system testing. Some of the input tests may need to be done ahead of overall system testing to the extent that the tests affect the overall performance. The test coordinator or coordinators need to have full knowledge of the intent of the scheme, isolation points, simulation scenarios, and restoration to normal procedures.
>
> The concept is to validate the overall performance of the scheme, including the logic where applicable, to validate the overall throughput times against system modeling for different types of contingencies, and to verify scheme performance as well as the inputs and outputs.

If a RAS passes a functional test, it is not necessary to provide that specific information to the RC because that is the expected result and requires no further action. If a segment of a RAS fails a functional test, the status of that degraded RAS is required to be reported (in Real-time) to the Transmission Operator via PRC-001, Requirement R6, then to the RC via TOP-001-2, Requirement R5. Consequently, it is not necessary to include a similar requirement in this standard.

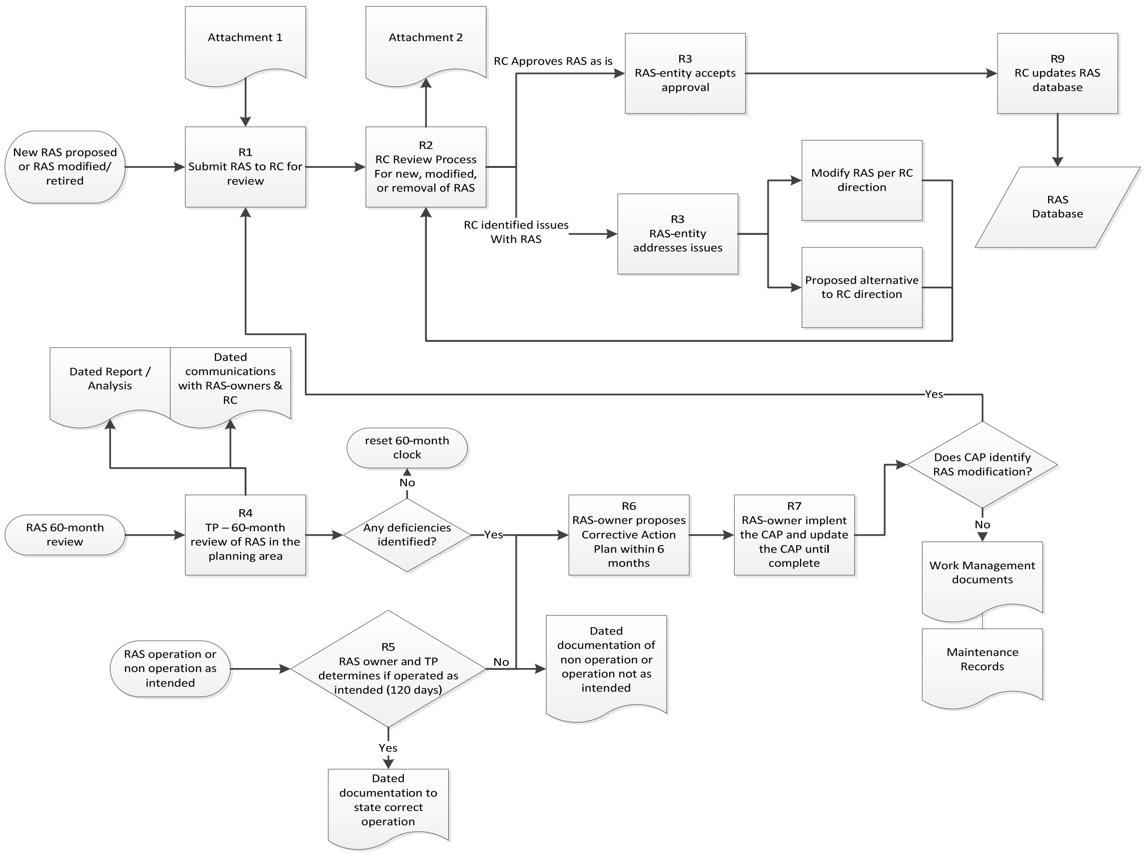
Requirement R9

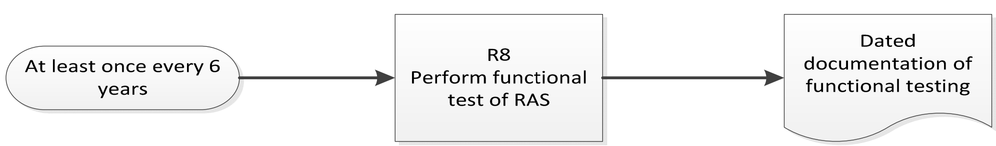
The RAS database required to be maintained by the RC in Requirement R9 ensures information regarding existing RAS is available to entities with a potential reliability need. Attachment 3 contains the minimum information that is required to be included about each RAS listed in the database. Additional information can be requested by the RC.

The information provided is sufficient for an entity with a reliability need to evaluate whether the RAS can impact its System. For example, a RAS performing generation rejection to mitigate an overload on a transmission line may cause a power flow change within an adjacent entity area. This entity should be able to evaluate the risk that a RAS poses to its System from the high-level information provided in the RAS database.

The RAS database does not need to list detailed settings or modeling information, but the description of the System performance issues, System conditions, and the intended corrective actions must be included. If additional details about the RAS operation are required, the entity may obtain the contact information of the RAS-entity from the RC.

The following diagrams depict the process flow of the PRC-012-2 requirements.





Technical Justifications for Attachment 1 Content
Supporting Documentation for RAS Review

To perform an adequate review of the expected reliability implications of a Remedial Action Scheme (RAS), it is necessary for the RAS-owner(s) to provide a detailed list of information describing the RAS to the designated RAS-entity. If there are multiple owners of the RAS, information may be needed from all owners, but a single RAS-owner (designated as the RAS-entity) is assigned the responsibility of compiling the RAS data and presenting it to the reviewing RC(s). Other RAS-owners may participate in the review, if they choose.

The necessary data ranges from a general overview of the RAS to summarized results of transmission planning studies, to information about hardware used to implement the RAS. Coordination between the RAS and other RAS and protection and control systems will be examined for possible adverse interactions. This review can include wide-ranging electrical design issues involving the specific hardware, logic, telecommunications, and other relevant equipment and controls that make up the RAS.

Attachment 1

The following checklist identifies important RAS information for each new or functionally modified[3] RAS that the RAS-entity shall document and provide to the RC for review pursuant to Requirement R1. When a RAS has been previously reviewed, only the proposed modifications to that RAS require review; however, it will be helpful to each reviewing RC if the RAS-entity provides a summary of the previously approved RAS functionality.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.

   Provide a description of the RAS to give an overall understanding of the functionality and a map showing the location of the RAS. Identify other protection and control systems requiring coordination with the RAS. See RAS Design below for additional information.

   Provide a single-line drawing(s) showing all sites involved. The drawing(s) should provide sufficient information to allow the RC review team to assess design reliability, and should include information such as the bus arrangement, circuit breakers, the associated switches, etc. For each site, indicate whether detection, logic, action, or a combination of these is present.

2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.

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[3]Functionally Modified: Any modification to a RAS beyond the replacement of components that preserve the original functionality is a functional modification.

3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP.
   [Reference NERC Reliability Standard PRC-012-2, Requirements R5 and R7]

   Provide a description of any functional modifications to a RAS that are part of a CAP that are proposed to address performance deficiency(ies) identified in the periodic evaluation pursuant to Requirement R4, or the analysis of an actual RAS operation pursuant to Requirement R5. A copy of the most recent CAP must be submitted in addition to the other data specified in Attachment 1.

4. Initial data to populate the RAS database.

   a. RAS name

   b. RAS-entity and contact information

   c. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent 60-full-calendar-month (Requirement R4) evaluation date; and, date of retirement, if applicable

   d. System performance issue or reason for installing the RAS (*e.g.*, thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery)

   e. Description of the contingencies or System conditions for which the RAS was designed (initiating conditions)

   f. Corrective action taken by the RAS

   g. Any additional explanation relevant to high level understanding of the RAS

      Note: This is the same information as is identified in Attachment 3. Supplying the data at this point in the review process ensures a more complete review and minimizes any administrative burden on the reviewing RC(s).

II. Functional Description and Transmission Planning Information

1. Contingencies and system conditions that the RAS is intended to remedy.
   [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.1]

   a. The System conditions that would result if no RAS action occurred should be identified.

   b. Include a description of the System conditions that should arm the RAS so as to be ready to take action upon subsequent occurrence of the critical system contingencies or other operating conditions when RAS action is intended to occur. If no arming conditions are required, this should also be stated.

   c. Event-based RAS are triggered by specific contingencies that initiate mitigating action. Condition-based RAS may also be initiated by specific contingencies, but specific Contingencies are not always required. These triggering Contingencies and/or conditions should be identified.

2. The actions to be taken by the RAS in response to disturbance conditions.
   [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.2]

   Mitigating actions are designed to result in acceptable System performance. These actions should be identified, including any time constraints and/or "backup" mitigating measures that may be required in case of a single RAS component failure.

3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), system conditions, and contingencies analyzed on which the RAS design is based, and when those technical studies were performed. [Reference NEC Reliability Standard PRC-014, R3.2]

   Review the scheme purpose and impact to ensure it is (still) necessary, serves the intended purposes, and meets current performance requirements. While copies of the full, detailed studies may not be necessary, any abbreviated descriptions of the studies must be detailed enough to allow the reviewing RC(s) to be convinced of the need for the scheme and the results of RAS-related operations.

4. Information regarding any future system plans that will impact the RAS.
   [Reference NERC Reliability Standard PRC-014, R3.2]

   The RC's other responsibilities under the NERC Reliability Standards focus on the Operating Horizon, rather than the Planning Horizon. As such, the RC is less likely to be aware of any longer range plans that may have an impact on the proposed RAS. Such knowledge of future Plans is helpful to provide perspective on the capabilities of the RAS.

5. Documentation showing that the possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following:
   [Reference NERC Reliability Standard PRC-012, R1.4]

   a. The BES shall remain stable.

   b. Cascading shall not occur.

   c. Applicable Facility Ratings shall not be exceeded.

   d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

   e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

6. An evaluation indicating that the RAS settings and operation avoids adverse interactions with other RAS, and protection and control systems.
   [Reference NERC Reliability Standards PRC-012, R1.5 and PRC-014, R3.4]

   RAS are complex schemes that may take action such as tripping load or generation or re-configuring the system. Many RAS depend on sensing specific System configurations to determine whether they need to arm or take actions. An examples of an adverse interaction: A RAS that reconfigures the System also changes the available fault duty, which can affect distance relay overcurrent ("fault detector") supervision and ground overcurrent protection coordination.

7. Identification of other affected RCs.

   This information is needed to aid in information exchange among all affected entities and coordination of the RAS with other RAS and protection and control systems.

III. Implementation

1. Documentation describing the applicable equipment used for detection, telecommunications, transfer trip, logic processing, and monitoring.

Detection

Detection and initiating devices, whether for arming or triggering action, should be designed to be secure. Several types of devices have been commonly used as disturbance, condition, or status detectors:

- Line open status (event detectors),
- Protective relay inputs and outputs (event and parameter detectors),
- Transducer and IED (analog) inputs (parameter and response detectors),
- Rate of change (parameter and response detectors).

Telecommunications Channels and Transfer Trip Equipment

Telecommunications channels used for sending and receiving RAS information between sites and/or transfer trip devices should meet at least the same criteria as other relaying protection communication channels. Discuss performance of any non-deterministic communication systems used (such as Ethernet).

The scheme logic should be designed so that loss of the channel, noise, or other channel or equipment failure will not result in a false operation of the scheme.

It is highly desirable that the channel equipment and communications media (power line carrier, microwave, optical fiber, etc.) be owned and maintained by the RAS-owner, or perhaps leased from another entity familiar with the necessary reliability requirements. All channel equipment should be monitored and alarmed to the dispatch center so that timely diagnostic and repair action shall take place upon failure. Publicly switched telephone networks are generally an undesirable option.

Communication channels should be well labeled or identified so that the personnel working on the channel can readily identify the proper circuit. Channels between entities should be identified with a common name at all terminals.

Transfer trip equipment, when separate from other RAS equipment, should be monitored and labeled similarly to the channel equipment.

Logic Processing

All RAS require some form of logic processing to determine the action to take when the scheme is triggered. Required actions are always scheme dependent. Different actions may be required at different arming levels or for different contingencies. Scheme logic may be achievable by something as simple as wiring a few auxiliary relay contacts or by much more complex logic processing.

Platforms that have been used reliably and successfully include PLCs in various forms, personal computers (PCs), microprocessor protective relays, remote terminal units (RTUs), and logic processors. Single-function relays have been used historically to implement RAS, but this approach is now less common except for very simple new RAS or minor additions to existing RAS.

Monitoring by SCADA/EMS should include at least

- Whether the scheme is in-service or out of service.
  - For RAS that are armed manually, the arming status may be the same as whether the RAS is in-service or out of service.
  - For RAS that are armed automatically, these two states are independent because a RAS that has been placed in service may be armed or unarmed based on whether the automatic arming criteria have been met.
- The current operational state of the scheme (available or not).
- In cases where the RAS requires single-component failure performance (redundancy), the minimal status indications should be provided separately for each system.
  - The minimum status is generally sufficient for operational purposes; however, where possible it may be useful to provide additional information regarding partial failures or the status of critical components to allow the RAS-owner to more efficiently troubleshoot a reported failure. Whether this capability exists will depend in part on the design and vintage of equipment used in the RAS. While all schemes should provide the minimum level of monitoring, new schemes should be designed with the objective of providing monitoring at least similar to what is provided for microprocessor-based Protection Systems.

2. Information on detection logic and settings/parameters that control the operation of the RAS. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.3]

Several methods to determine line or other equipment status are in common use, often in combination:

a. Auxiliary switch contacts from circuit breakers and disconnect switches (52a/b, 89a/b)—the most common status monitor; “a” contacts exactly emulate actual breaker status, while “b” contacts are opposite to the status of the breaker;

b. Undercurrent detection—a low level indicates an open condition, including at the far end of a line; pickup is typically slightly above the total line-charging current;

c. Breaker trip coil current monitoring—typically used when high-speed RAS response is required, but usually in combination with auxiliary switch contacts and/or other detection because the trip coil current ceases when the breaker opens; and

d. Other detectors such as angle, voltage, power, frequency, rate of change of these, out of step, etc.—very dependent on specific scheme requirements, but some forms may substitute for or enhance current monitoring detection.

Both RAS arming and action triggers often require monitoring of analog quantities such as power, current, and voltage at one or more locations and are set to detect a specific level of the pertinent quantity. These monitors may be relays, meters, transducers, or other devices

3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in service or is being maintained.

   In this context, a multifunction device (e.g., microprocessor-based relay) is a single component that is used to perform the function of a RAS in addition to protective relaying and/or SCADA simultaneously. It is important that other applications in the multifunction device do not compromise the functionality of the RAS when the device is in service or when it is being maintained. The following list outlines considerations when the RAS function is applied in the same microprocessor-based relay as equipment protection functions:

   a. Describe how the multifunction device is applied in the RAS.

   b. Show the general arrangement and describe how the multi-function device is labeled in the design and application, so as to identify the RAS and other device functions.

   c. Describe the procedures used to isolate the RAS function from other functions in the device.

   d. Describe the procedures used when each multifunction device is removed from service and whether coordination with other protection schemes is required.

   e. Describe how each multifunction device is tested, both for commissioning and during periodic maintenance testing, with regard to each function of the device.

f. Describe how overall periodic RAS functional and throughput tests are performed if multifunction devices are used for both local protection and RAS.

g. Describe how upgrades to the multifunction device, such as firmware upgrades, are accomplished. How is the RAS function taken into consideration?

Other devices that are usually not considered multifunction devices such as auxiliary relays, control switches, and instrument transformers may serve multiple purposes such as protection and RAS. Similar concerns apply for these applications as noted above.

4. Documentation showing that a single-component failure in a 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 is designed. The documentation should describe or illustrate how the implementation design achieves this objective. [Reference NERC Reliability Standard PRC-012, R1.3]

   RAS automatic arming, if applicable, is vital to RAS and System performance and is therefore included in this requirement.

   Acceptable methods to achieve this objective include the following:

   a. Providing redundancy of RAS components listed below:

      i. Protective or auxiliary relays used by the RAS.

      ii. Communications systems necessary for correct operation of the RAS.

      iii. Sensing devices used to measure electrical quantities used by the RAS.

      iv. Station dc supply associated with RAS functions.

      v. Control circuitry associated with RAS functions through the trip coil(s) of the circuit breakers or other interrupting devices.

      vi. Computers or programmable logic devices used to analyze information and provide RAS operational output.

   b. 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.

   c. Using alternative automatic actions to back up failures of single RAS components.

   d. 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.

5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies important RAS information for each existing RAS to be retired that the RAS-entity shall document and provide to the Reliability Coordinator for review pursuant to Requirement R1.

1. Information necessary to ensure that the Reliability Coordinator is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of technical studies, if applicable, upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

   While the documentation necessary to evaluate RAS removals is not as extensive as for new or functionally modified RAS, it is still vital that, when the RAS is no longer available, System performance will still meet the appropriate (usually TPL) requirements for the Contingencies or System conditions that the RAS had been installed to remediate.

Technical Justification for Attachment 2 Content

Reliability Coordinator RAS Review Checklist

Attachment 2 is a checklist provided to assist the RC in identifying reliability considerations generally relevant to aspects of RAS design and implementation, and also for the purpose of facilitating consistent reviews continent-wide for each RAS to be installed or functionally modified. Most of the checklist items should be applicable to most RAS. There may be checklist items that are not applicable to a given RAS in which case they may be noted as not applicable and skipped in the RC review. Depending on the specifics of the RAS under review, it is possible that other reliability considerations may be identified during the review. Any other reliability considerations, along with their resolution with respect to the particular RAS under review, should be documented along with the Attachment 2 items that were applicable to the specific RAS under review.

Technical Justifications for Attachment 3 Content
Database Information

Attachment 3 contains the minimum information that the RC must consolidate into its database for each RAS in its area.

1. RAS name.
   - The name used to identify the RAS.
2. RAS-entity and contact information.
   - A reliable phone number or email address should be included to contact the RAS-entity if more information is needed. At a minimum, the name of the RAS-entity responsible for the RAS information should be provided.
3. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent 60-full-calendar-month (Requirement R4) evaluation date; and, date of retirement, if applicable.
   - Specify each applicable date.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery).
   - A short description of the reason for installing the RAS is sufficient, as long as the main System issues addressed by the RAS can be identified by someone with a reliability need.
5. Description of the contingencies or System conditions for which the RAS was designed (initiating conditions).
   - A high level summary of the conditions/contingencies is expected. Not all combinations of conditions are required to be listed.
6. Corrective action taken by the RAS.
   - A short description of the actions should be given. For schemes shedding load or generation, the maximum amount of megawatts should be included.
7. Any additional explanation relevant to high-level understanding of the RAS.
   - If deemed necessary, any additional information can be included in this section, but is not mandatory.

Implementation Plan for PRC-012-2

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

Requested Approval

- PRC-012-2 – Remedial Action Schemes

Requested Retirements of Reliability Standards[1]

- PRC-012-0 – Special Protection System Review Procedure
- PRC-013-0 – Special Protection System Database
- PRC-014-0 – Special Protection System Assessment
- PRC-012-1 – Special Protection System Review Procedure
- PRC-013-1 – Special Protection System Database
- PRC-014-1 – Special Protection System Assessment
- PRC-015-0 – Special Protection System Data and Documentation
- PRC-016-0.1 – Special Protection System Misoperations
- PRC-015-1 – Special Protection System Data and Documentation
- PRC-016-1 – Special Protection System Misoperations

Prerequisite Approval

- Revised definition of “Remedial Action Scheme”

Applicable Entities

- Reliability Coordinator
- Transmission Planner
- RAS-owner – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS
- RAS-entity – the RAS-owner designated to represent all RAS-owner(s) for coordinating the review and approval of a RAS

[1] Retirement includes withdrawal of pending Reliability Standards.

General Considerations

On November 13, 2014, the NERC Board of Trustees approved revisions to the definition for RAS and associated revisions to related Reliability Standards to consolidate that term with the Glossary term "Special Protection System" (SPS).

In its February 3, 2015 petition to the Commission for approval of the definition of RAS and associated Reliability Standards ("Petition"), NERC noted that, although PRC-012-0, PRC-013-0, and PRC-014-0 were neither approved nor remanded by the Commission in Order No. 693 and were therefore not enforceable, NERC revised these standards to account for the RAS definition revision and changed relevant version numbers to reflect the change. Because of this change, NERC requested retirement of PRC-012-0, PRC-013-0, and PRC-014-0, and provided, for informational purposes only, updated Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1. In the same Petition, NERC requested approval of Reliability Standards PRC-015-1 and PRC-016-1 and retirement of PRC-015-0 and PRC-016-0.1, again implementing changes stemming from the revised definition of RAS.

The Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to accept the revisions on June 18, 2015. As of the date of posting of this Implementation Plan, however, the Commission has not issued an Final Order approving and retirement the Reliability Standards enumerated above. Because the standard drafting team for this project has determined that the retirements requested above are necessary to ensure a seamless transition to consolidation of these standards in PRC-012-2, NERC reiterates the requests for retirements already submitted in the Petition and those that are still pending at the Commission.

Effective Dates for PRC-012-2

The proposed Reliability Standard PRC-012-2 shall become effective on the later of the day after the revised definition of Remedial Acton Scheme becomes effective or the first day of the first calendar quarter that is twelve (12) months after the date the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards

The Reliability Standards for retirement shall be retired immediately prior to the Effective Date of PRC-012-2 in the particular jurisdiction in which the standard is becoming effective.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)
PRC-012-2

DO NOT use this form for submitting comments. Use the electronic form to submit comments on draft 1 of **PRC-012-2 – Remedial Action Schemes**. The electronic comment form must be submitted by **8 p.m. Eastern, Monday, October 5, 2015.**

Documents and information about this project are available on the project page. If you have questions, contact Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

Background Information

This project is addressing all aspects of Remedial Action Schemes (RAS) and Special Protection Systems (SPS) contained in the RAS/SPS-related Reliability Standards: PRC-012-1, PRC-013-1, PRC-014-1, PRC-015-1, and PRC-016-1. The maintenance of the Protection System components associated with RAS (PRC-017-1 Remedial Action Scheme Maintenance and Testing) are already addressed in PRC-005. PRC-012-2 addresses the testing of the non-Protection System components associated with RAS/SPS

In FERC Order No. 693 (dated March 16, 2007), the Commission identified PRC-012-0, PRC-013-0, and PRC-014-0 as “fill-in-the-blank” standards and did not approve or remand them. These standards are applicable to the Regional Reliability Organizations (RROs), assigning the RROs the responsibility to establish regional procedures and databases, and to assess and document the operation, coordination, and compliance of RAS/SPS. The deference to regional practices precludes the consistent application of RAS/SPS-related Reliability Standard requirements.

The proposed draft of PRC-012-2 corrects the applicability of the fill-in-the-blank standards by assigning the requirement responsibilities to the specific users, owners, and operators of the Bulk-Power System; and incorporates the reliability objectives of all the RAS/SPS-related standards.

45-day Formal Comment Period

The drafting team is soliciting stakeholder comments and feedback on the first draft of PRC-012-2. The team appreciates the feedback you provided during the informal comment period earlier this year and considered all of your suggestions. While many of your thoughts were incorporated into this product, a few were not and the drafting team offers the following explanations.

Choice of applicable entity in specific requirements: The drafting team selected the functional entity they assert is the most capable of performing the required actions. The drafting team recognizes that in some instances the specified entity will need to collaborate with or obtain information from other entities. For example, in Requirement R5, the RAS-owner is tasked with analyzing RAS operations. The RAS-owner was designated because they own the RAS and are responsible for maintaining the performance of the RAS. The drafting team recognizes that the RAS-owner may need to obtain information from entities such as the Transmission Operator, Transmission Planner, Balancing Authority, or others to complete the analysis but contends that ultimate responsibility should remain with the RAS-owner.

Periodic Planning Evaluation Considerations: Requirement R4 mandates that the Transmission Planner (TP) perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS.

In structuring Requirement R4, the SDT considered the issue of the TP reviewing the RAS design made by the RAS-owner. Although the TP is not involved in the detailed design of the RAS, the SDT asserts that the TP is aware, to some extent, of the redundancy level of the RAS design from the initial planning studies. Requirement R4 is a planning evaluation to assess the impact of System changes over time on the RAS effectiveness and is not intended to be a RAS design review.

The language used in the current Requirement R4, Part 4.4 is aligned with the language of Requirement R1.3 in PRC-012-0 (RAS single component failure).The evaluation of a RAS under Requirement R4, Part 4.4 will consider the following three scenarios:

1. The RAS was originally designed such that a “single component failure” does not prevent RAS operation in-whole. Due to System changes that may affect achieving the System performance requirement(s), the TP must re-evaluate whether the operation of the RAS still meets them. If it does not, then a CAP must be developed per Requirement R6 to meet “single component failure” performance requirements.

2. The RAS was originally designed such that a “single component failure” could cause the RAS to not operate when intended. Therefore, System performance when the RAS fails to operate must be evaluated. For deficient System performance, a CAP must be developed per Requirement R6 to meet “single component failure” performance requirements.

3. The RAS was designed such that a “single component failure” could cause part but not all of the RAS to not operate, yet still meet the System performance requirement(s) (e.g. over-arming used to mitigate “single component failure” for load shedding or generation rejection). Due to System changes that may affect achieving the System performance requirement(s), the TP must re-evaluate whether partial operation of the RAS still meets them. If it does not, then a CAP must be developed per Requirement R6 to meet “single component failure” performance requirements.

In all cases, detailed design review is not required. The SDT recognizes that involvement of the RAS-owner may be necessary for the TP to be aware of the consequences of single component failure for its RAS.

CAP Development Considerations: The drafting team selected the RAS-owner as the applicable entity to develop, submit, and implement CAPs associated with RAS performance because they own the RAS, are responsible for maintaining the performance of the RAS, and make all of the financial decisions regarding the RAS. The six-month timeframe to develop a CAP was selected to provide enough time for engineering studies to analyze possible modifications to the RAS. The six months is the maximum timeframe. The SDT anticipates that most CAPs can be developed in less time. The glossary definition of a CAP includes the work schedules associated with implementing and completing actions within the CAP. The implementation timeframe should not impact System reliability because the RC will determine whether the RAS can remain in service, or if other System operating limits must be imposed. The RAS-owner must submit the CAP to the RC. The RC is not required to approve a CAP that does not require functional modifications to the RAS; however, the drafting team expects the RC would provide feedback on any concerns with CAP adequacy. A CAP that does require functional modifications will be reviewed and approved by the RC in accordance with Requirements R1, R2, and R3.

Functional Testing: The drafting team asserts that the functional testing of RAS should remain in PRC-012-2 and not be included in PRC-005.While the drafting team agrees that many RAS have Protection System components that will be maintained in accordance with PRC-005, the purpose of the functional testing is to verify the control equipment operation and confirm the overall RAS performance rather than the performance of individual Protection System components. PRC-005 does not include the maintenance of RAS controllers such as PLCs, computers, or the control functions of microprocessor relays. There is no double jeopardy because PRC-012-2 specifically requires the verification of only non-Protection System components. The drafting team contends that functional testing is complementary to the Protection System component maintenance required in PRC-005. An entity could maintain its Protection System components in association with a functional testing of a RAS and document it for compliance with its Protection System Maintenance Plan for PRC-005.

RAS Database and Attachment 3: The drafting team selected the Reliability Coordinator to maintain the RAS database because the RC is the reviewing entity for new and functionally modified RAS and as such receives the pertinent data from the RAS-entity in Attachment 1. The RAS database serves as a repository of information about all RAS in an RC Area that enables entities with a reliability-related need access to the information through the RC. The data in Attachment 3 is the minimum an RC is required to maintain; however, the RC has the discretion to require additional information deemed necessary for a high-level understanding of a RAS. The drafting team contends it is not necessary to require detailed information for every RAS in the database as that would make database maintenance a burden for both the RC and the entities, while bringing little improvement to reliability. While the SDT agrees that detailed information may be important to an entity with a reliability-related need, it was agreed that such cases are specific enough to be treated individually and not systematically through a standard requirement. The drafting team also asserts that a requirement for an entity to provide detailed modeling information to other registered entities is not necessary. Entities that have a reliability-related need for this information have multiple avenues to get the data; e.g., regional model building processes, Planning Coordinator, and/or direct request to the RAS-owner.

The drafting team is charged with assigning the requirements of the new standard to the specific users, owners, and operators of the Bulk-Power System while incorporating the reliability objectives of all the RAS/SPS-related standards. In drafting this standard, the team has worked diligently to minimize the changes that will be required from your existing processes. The drafting team requests that you read the standard including the rationales and technical justifications thoroughly and provide your thoughtful comments. The electronic comment form must be completed by **8 p.m. Eastern Monday, October 5, 2015.**

Questions

Requirements R1, R2, and R3 pertain to the submittal of Attachment 1 information to the Reliability Coordinator (RC) for the review of a RAS, the RC using Attachment 2 as a guide for performing the RAS review, and the RC approving the RAS prior to the RAS being placed in service. Question 1 is relevant to these activities.

1. **RAS review and approval:** Do you agree with the RAS review process outlined by Requirements R1, R2, and R3? If no, please provide the basis for your disagreement and an alternate proposal.

   ☐ Yes
   ☐ No
   Comments:

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

2. **RAS Periodic Evaluations:** Do you agree with the RAS planning evaluation process outlined by Requirement R4? If no, please provide the basis for your disagreement and an alternate proposal.

   ☐ Yes
   ☐ No
   Comments:

3. **RAS Inadvertent Operation:** Do you agree with Requirement 4 Part 4.3 and Attachment 1 which stipulates that RAS inadvertent operation due to a single component malfunction still satisfies the System performance requirements common to TPL-001-4 P1-P7 events listed in Parts 4.3.1-4.3.5? (Note that this requirement remains the same as PRC-012-0 R1.4 except for the allowance for designed-in security that would prevent RAS inadvertent operation for any single component malfunction). If no, please provide the basis for your disagreement and an alternate proposal.

   ☐ Yes
   ☐ No

Comments:

4. **RAS Single Component Failure:** Do you agree with Requirement 4 Part 4.4 and Attachment 1 which stipulates that any RAS intended to satisfy System performance requirements in a TPL standard must still satisfy those requirements when experiencing a single component failure? (Note that this requirement remains unchanged from PRC-012-0 R1.3.) If no, please provide the basis for your disagreement and an alternate proposal.

☐ Yes
☐ No
Comments:

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

5. **Corrective Action Plans:** Do you agree that the application of Requirements R6 and R7 would address the reliability objectives associated with CAPs? If no, please provide the basis for your disagreement and an alternate proposal.

☐ Yes
☐ No
Comments:

6. **Implementation Plan:** Do you agree with the Implementation Plan? If no, please provide the basis for your disagreement and an alternate proposal.

☐ Yes
☐ No
Comments:

7. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

Comments:

Mapping Document

Project 2010-5.3 Phase 3 of Protection Systems: Remedial Action Schemes

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include: R1.1. Description of the process for submitting a proposed RAS for Regional Reliability Organization review. R1.2. Requirements to provide data that describes design, operation, and modeling of a RAS. R1.3. 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.	**PRC-012-1 R.1.1**: Covered by Requirements R1, R2 and R3. **PRC-012-1 R.1.2**: Covered by Requirement R1, Attachment 1 **PRC-012-1 R.1.3**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4.4 **PRC-012-1 R.1.4**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2, and Requirement R4.3.	**R1.** Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity shall submit the information identified in Attachment 1 for review to the Reliability Coordinator(s) that coordinates the area(s) where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to the RAS-entity. **R3.** Following the review performed pursuant to Requirement R2, the RAS-entity shall address each identified issue and obtain approval from each reviewing Reliability Coordinator, prior to placing a new or functionally modified RAS in service or retiring an existing RAS. **R4.** Each Transmission Planner shall perform an evaluation of each RAS within its planning area at least once every 60 full calendar months and provide the RAS-

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1.4. Requirements to demonstrate 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. R1.5. Requirements to demonstrate the proposed RAS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures. R1.6. Regional Reliability Organization definition of misoperation. R1.7. Requirements for analysis and documentation of corrective action plans for all RAS misoperations. R1.8. Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure. R1.9. Determination, as appropriate, of maintenance and testing requirements.	**PRC-012-1 R.1.5**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4.2. **PRC-012-1 R.1.6**: Covered by Requirement R5 **PRC-012-1 R.1.7**: Covered by Requirements R4 and R6 **PRC-012-1 R.1.8**: PRC-012-2 NERC Standards Development Process **PRC-012-1 R.1.9**: Covered by Requirement R8	owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether: **4.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.2** The RAS avoids adverse interactions with other RAS, and protection and control systems **4.3** The possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following: **4.3.1** The BES shall remain stable. **4.3.2** Cascading shall not occur. **4.3.3** Applicable Facility Ratings shall not be exceeded. **4.3.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. **4.3.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.4 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 is designed. **R5.** Each RAS-owner shall, within 120-calendar days of a RAS operation or failure of a RAS to operate when expected, analyze the RAS performance and provide the results of the analysis, including any identified deficiencies, to its reviewing Reliability Coordinator(s). The RAS operational performance analysis shall determine whether: **5.1** The System events and/or conditions appropriately triggered the RAS. **5.2** The RAS responded as designed. **5.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.4** The RAS operation resulted in any unintended or adverse BES response. **R6.** Within six full calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall participate in

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s). **R8.** At least once every six calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components.
R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-013-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a RAS installed shall maintain a RAS database. The database shall include the following types of information: R1.1. Design Objectives — Contingencies and system conditions for which the RAS was designed, R1.2. Operation — The actions taken by the RAS in response to Disturbance conditions, and R1.3. Modeling — Information on detection logic or relay settings that control operation of the RAS.	**PRC-013-1 R1**: Covered by Requirement R9 **PRC-013-1 R1.1**: Covered by Requirement R9, Attachment 3 **PRC-013-1 R1.2**: Covered by Requirement R9, Attachment 3 **PRC-013-1 R1.3**: Covered by Requirement R9, Attachment 3	**R9.** Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once each calendar year.
R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.	**PRC-014-1 R1**: Covered by Requirement R4	**R4.** Each Transmission Planner shall perform an evaluation of each RAS within its planning area at least once every 60 full calendar months and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether: **4.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.3** The possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following: **4.3.1** The BES shall remain stable. **4.3.2** Cascading shall not occur. **4.3.3** Applicable Facility Ratings shall not be exceeded. **4.3.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.3.5 Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.4** 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 is designed.
R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all RAS installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).	<u>**PRC-014-1 R2**</u>: Covered by Requirement R4	**R4.** Each Transmission Planner shall perform an evaluation of each RAS within its planning area at least once every 60 full calendar months and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether: **4.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.3** The possible inadvertent operation of the RAS resulting from any single RAS component

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		inadvertent operation satisfies all of the following: **4.3.1** The BES shall remain stable. **4.3.2** Cascading shall not occur. **4.3.3** Applicable Facility Ratings shall not be exceeded. **4.3.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. **4.3.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.4** 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 is designed.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R3. The documentation of the Regional Reliability Organization's RAS assessment shall include the following elements: R3.1. Identification of group conducting the assessment and the date the assessment was performed. R3.2. Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed. R3.3. Identification of RAS that were found not to comply with NERC standards and Regional Reliability Organization criteria. R3.4. Discussion of any coordination problems found between a RAS and other protection and control systems. R3.5. Provide corrective action plans for non-compliant RAS.	**PRC-014-1 R2**: Covered by Requirement R4 **PRC-014-1 R3.1**: Covered by Requirement R4 **PRC-014-1 R3.2**: Covered by Requirement R4 **PRC-014-1 R3.3**: Covered by Requirement R4 **PRC-014-1 R3.4**: Covered by Requirement R4 **PRC-014-1 R3.5**: Covered by Requirement R6	**R4.** Each Transmission Planner shall perform an evaluation of each RAS within its planning area at least once every 60 full calendar months and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether: **4.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.3** The possible inadvertent operation of the RAS resulting from any single RAS component inadvertent operation satisfies all of the following: **4.3.1** The BES shall remain stable. **4.3.2** Cascading shall not occur. **4.3.3** Applicable Facility Ratings shall not be exceeded. **4.3.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.3.5 Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.4** 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 is designed. **R6.** Within six full calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s).

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall maintain a list of and provide data for existing and proposed RAS as specified in Reliability Standard PRC-013-1 R1.	**PRC-015-1 R1**: Covered by Requirement R1, Attachment 1.	**R1.** Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity shall submit the information identified in Attachment 1 for review to the Reliability Coordinator(s) that coordinates the area(s) where the RAS is located.
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-1_R1 prior to being placed in service.	**PRC-015-1 R2**: Covered by Requirements R1, Attachment 1; R2, Attachment 2; and R3.	**R1.** Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity shall submit the information identified in Attachment 1 for review to the Reliability Coordinator(s) that coordinates the area(s) where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to the RAS-entity. **R3.** Following the review performed pursuant to Requirement R2, the RAS-entity shall address each identified issue and obtain approval from each reviewing Reliability Coordinator, prior to placing a new or functionally modified RAS in service or retiring an existing RAS.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide	Retired P81	N/A

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
documentation of RAS data and the results of Studies that show compliance of new or functionally modified RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).		

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall analyze its RAS operations and maintain a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-1_R1.	**PRC-016-1 R1**: Covered by Requirement R5	**R5.** Each RAS-owner shall, within 120-calendar days of a RAS operation or failure of a RAS to operate when expected, analyze the RAS performance and provide the results of the analysis, including any identified deficiencies, to its reviewing Reliability Coordinator(s). The RAS operational performance analysis shall determine whether: **5.1** The System events and/or conditions appropriately triggered the RAS. **5.2** The RAS responded as designed. **5.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.4** The RAS operation resulted in any unintended or adverse BES response.
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall take corrective actions to avoid future misoperations.	**PRC-016-1 R2**: Covered by Requirements R6 and R7.	**R6.** Within six full calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s). **R7.** For each CAP submitted pursuant to Requirement R6, each RAS-owner shall: **7.1** Implement the CAP.

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		7.2 Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).	<u>**PRC-016-1 R3**</u>: Covered by Requirements R5, R6, and R7, Attachment 1.	**R5.** Each RAS-owner shall, within 120-calendar days of a RAS operation or failure of a RAS to operate when expected, analyze the RAS performance and provide the results of the analysis, including any identified deficiencies, to its reviewing Reliability Coordinator(s). The RAS operational performance analysis shall determine whether: **5.1** The System events and/or conditions appropriately triggered the RAS. **5.2** The RAS responded as designed. **5.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.4** The RAS operation resulted in any unintended or adverse BES response. **R6.** Within six full calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s).

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		R7. For each CAP submitted pursuant to Requirement R6, each RAS-owner shall: **7.1** Implement the CAP. **7.2** Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justification Document

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

This document provides the standard drafting team (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-012-2. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange

- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justifications for PRC-012-2, Requirement R1	
VRF for Requirement R1 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of an entity to submit Attachment 1 information to the responsible Reliability Coordinator for review prior to placing a new or modified RAS in service or retiring an existing RAS could introduce risks to the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R1 relates to two of these areas, specifically (i) protection systems and their coordination; and (ii) clearer criteria for operationally critical facilities. Requirement R1 mandates that entities comply with a review process for new or modified RAS or retirement of RAS. Among the elements of such reviews is the coordination between RAS and other RAS and between RAS and protection and control systems. Requirement R1 also mandates that the RAS-entity provide the Reliability Coordinator relevant RAS information regarding the design and implementation for each new or functionally modified RAS.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements, so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-012-1, Requirement 1, Parts R1.1 – R1.5 which specifies attributes of the RRO process to review RAS (R1.1), provision of pertinent RAS data (R1.2), dependability (R1.3) and security (R1.4) of design, and coordination with other RAS and protection systems (R1.5), and has a Medium VRF.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of an entity to submit Attachment 1 information to the responsible Reliability Coordinator for review prior to placing a new or modified RAS in service or retiring an existing RAS could introduce risks to the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R1	
VRF for Requirement R1 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The RAS-entity failed to submit the information identified in Attachment 1 to one or more of the Reliability Coordinator(s) in accordance with Requirement R1.

VSL Justifications for PRC-012-2, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-012-1, Requirements R1.1 – R1.5 which had four established Levels of Non-Compliance. The requirement is binary with only a Severe VSL so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2b: N/A
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R2	
VRF for Requirement R2 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R2 because failure of a Reliability Coordinator to perform the RAS reviews and identify potential risks presented by the RAS could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R2 relates to one of these areas, specifically, protection systems and their coordination. Requirement R2 mandates that Reliability Coordinators review the RAS to determine if a RAS avoids adverse interactions with other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-014-1, Requirement R1, which is related to the review of RAS.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R2 because failure of a Reliability Coordinator to perform the RAS reviews and identify potential risks presented by the RAS could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R2	
VRF for Requirement R2 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30-calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30-calendar days but less than or equal to 60-calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2 but was late by more than 60-calendar days but less than or equal to 90-calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90-calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in accordance with Requirement R2.

VSL Justifications for PRC-012-2, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-014-0, Requirement R1 which also had four established Levels of Non-Compliance. This requirement has VSLs comparable to the established Levels of Non-Compliance in that requirement, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R3	
VRF for Requirement R3 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of a RAS entity to address the reliability issues identified during the RC review before placing it into service could introduce risks to the BES that could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R3 relates to one of these areas, specifically protection systems and their coordination. Requirement R3 requires the RAS-entity to address each identified reliability issue which includes the coordination between RAS and other RAS and between RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-015-0 Requirement R2 which requires the entity to comply with the RRO procedure as defined in PRC-012-1 Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of a RAS entity to address the reliability issues identified during the RC review before placing it into service could introduce risks to the BES that could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R3	
VRF for Requirement R3 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The RAS-entity failed to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in service or retiring an existing RAS in accordance with Requirement R3.

VSL Justifications for PRC-012-2, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-015-0, Requirement R2 which has four established VSLs. This requirement is binary with only a Severe VSL so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2b: N/A
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R4	
VRF for Requirement R4 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R4 because failure to perform the periodic evaluation could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R4 relates to one of these areas, specifically protection systems and their coordination. Requirement R4 mandates that entities perform periodic evaluations of each RAS to ensure that changes in System conditions have not changed the effectiveness of the RAS to mitigate the events or System conditions for which it was designed. Requirement R4 incorporates all actions necessary to determine if a RAS avoids adverse interactions with other RAS and protection and control systems
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-2, Requirements R3 which requires the assessment of the effectiveness of UVLS Programs.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R4 because failure to perform the periodic evaluation could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R4	
VRF for Requirement R4 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Transmission Planner performed the evaluation in accordance with Requirement R4, in greater than 60-full calendar months but less than or equal to 61-full calendar months.	The Transmission Planner performed the evaluation in accordance with Requirement R4, in greater than 61-full calendar months but less than or equal to 62-full calendar months.	The Transmission Planner performed the evaluation in accordance with Requirement R4, in greater than 62-full calendar months but less than or equal to 63full calendar months. OR The Transmission Planner performed the evaluation in accordance with Requirement R4, but failed to evaluate one of the Parts 4.1 through 4.4.	The Transmission Planner performed the evaluation in accordance with Requirement R4, but in greater than 63-full calendar months. OR The Transmission Planner failed to perform the evaluation in accordance with Requirement R4. OR The Transmission Planner performed the evaluation in accordance with Requirement R4, but failed to evaluate two or more of the Parts 4.1 through 4.4.

VSLs for PRC-012-2, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
			OR The Transmission Planner performed the evaluation in accordance with Requirement R4, but failed to provide the results to one or more of the RAS-owner(s) and the reviewing Reliability Coordinator(s).

VSL Justifications for PRC-012-2, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-014-0, Requirement R1 which has four established Levels of Non-Compliance. This requirement has comparable VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R4	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R4	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R5	
VRF for Requirement R5 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R5 because failure to perform the RAS operational performance analysis could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R5 relates to one of these areas, specifically protection systems and their coordination. Requirement R5 mandates that entities perform RAS operational performance analysis to verify that the RAS operation and the resulting System performance was consistent with the Contingency events or System conditions for which it was designed. Requirement R5 incorporates all actions necessary to identify coordination issues between RAS and other RAS and between RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-2, Requirements R4 which requires evaluation of the UVLS Program performance during a voltage excursion event.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R5 because failure to perform the RAS operational performance analysis could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R5	
VRF for Requirement R5 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The RAS-owner performed the analysis in greater than 120-calendar days, but less than or equal to 130-calendar days in accordance with Requirement R5.	The RAS-owner performed the analysis in greater than 130-calendar days, but less than or equal to 140-calendar days in accordance with Requirement R5.	The RAS-owner performed the analysis in greater than 140-calendar days, but less than or equal to 150-calendar days in accordance with Requirement R5. OR The RAS-owner performed the analysis in accordance with Requirement R5, but failed to address one of the Parts 5.1 through 5.4.	The RAS-owner performed the analysis in greater than 150-calendar days. OR The RAS-owner failed to perform the analysis in accordance with Requirement R5. OR The RAS-owner performed the analysis in accordance with Requirement R5, but failed to address two or more of the Parts 5.1 through 5.4. OR The RAS-owner performed the analysis in accordance with

VSLs for PRC-012-2, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
			Requirement R5, but failed to provide the results to one or more of the reviewing Reliability Coordinator(s).

VSL Justifications for PRC-012-2, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0.1, Requirement R1, and PRC-012-1, Requirement R1.7, which have four established Levels of Non-Compliance. This requirement has comparable VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R5	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R5	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R6	
VRF for Requirement R6 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because the failure of an entity to develop a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R6 addresses one of these areas, specifically protection systems and their coordination. CAPs establish mitigation plans and timetable to address deficiencies that could cause adverse interactions between RAS and other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-016-0, Requirements R2 and R3 which require a RAS-owner take corrective actions to avoid future misoperations and provide documentation of the corrective action plans to the RRO.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because the failure of an entity to develop a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

VRF Justifications for PRC-012-2, Requirement R6	
VRF for Requirement R6 is Medium	
	preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The RAS-owner developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10-calendar days.	The RAS-owner developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10-calendar days but less than or equal to 20-calendar days.	The RAS-owner developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20-calendar days but less than or equal to 30-calendar days.	The RAS-owner developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30-calendar days. OR The RAS-owner developed a Corrective Action Plan and failed to submit it to one or more of its reviewing Reliability Coordinator(s) in accordance with Requirement R6. OR

VSLs for PRC-012-2, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
			The RAS-owner failed to develop a Corrective Action Plan in accordance with Requirement R6.

VSL Justifications for PRC-012-2, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0, Requirements R2 and R3, and has VSLs comparable to the established Levels of Non-Compliance in those requirements, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R6	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R6	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R7	
VRF for Requirement R7 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of an entity to implement a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R7 relates to one of these areas, specifically protection systems and their coordination. Implemented CAPs address deficiencies that could cause adverse interactions between RAS and other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-016-0, Requirements R2 and R3 which require a RAS-owner take corrective actions to avoid future misoperations and provide documentation of the corrective action plans to the RRO.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of an entity to implement a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

VRF Justifications for PRC-012-2, Requirement R7	
VRF for Requirement R7 is Medium	
	preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The RAS-owner implemented a CAP (Part 7.1), but failed to update the CAP (Part 7.2) if actions or timetables changed and failed to notify one or more of the reviewing Reliability Coordinator(s) (Part 7.3), in accordance with Requirement R7.	N/A	N/A	The RAS-owner failed to implement a CAP (Part 7.1) in accordance with Requirement R7.

VSL Justifications for PRC-012-2, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0, Requirement R2 and has VSLs comparable to the established Levels of Non-Compliance in that requirement, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Lower and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R8	
VRF for Requirement R8 is High	
NERC VRF Discussion	A High VRF is appropriate for this Requirement since failure to perform functional testing may allow latent failures to persist in a RAS. These latent failures could result in an unintended operation or a failure to operate, either of which could directly contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures. For these reasons, the requirement meets the NERC criteria for a High VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R8 has interactions in three of these areas, specifically (i) protection systems and their coordination, (ii) communication protocol and facilities, and (iii) appropriate use of transmission loading relief. RAS interactions occur with protection systems, utilize communication protocols and facilities for proper functioning, and are often used for transmission loading relief.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements, so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-005-3, Requirement R3 which requires the maintenance of Protection System Components and has a VRF of High.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A High VRF is appropriate for this Requirement since failure to perform functional testing may allow latent failures to persist in a RAS. These latent failures could result in an unintended operation or a failure to operate, either of which could directly contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures. For these reasons, the requirement meets the NERC criteria for a High VRF.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VRF Justifications for PRC-012-2, Requirement R8	
VRF for Requirement R8 is High	
mingle More than One Obligation	

VSLs for PRC-012-2, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The RAS-owner performed the functional test for a RAS as specified in Requirement R8, but was less than or equal to 30-calendar days late.	The RAS-owner performed the functional test for a RAS as specified in Requirement R8, but was more than 30-calendar days but less than or equal to 60-calendar days late.	The RAS-owner performed the functional test for a RAS as specified in Requirement R8, but was more than 60-calendar days but less than or equal to 90-calendar days late.	The RAS-owner performed the functional test for a RAS as specified in Requirement R8, but was more than 90-calendar days late. OR The RAS-owner failed to perform the functional test for a RAS as specified in Requirement R8.

VSL Justifications for PRC-012-2, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-017-0, Requirements R1 and R2, which had VSLs of Lower, Moderate, High, and Severe. This requirement has VSLs comparable to the established VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R8	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R9	
VRF for Requirement R9 is Lower	
NERC VRF Discussion	A Lower VRF is appropriate for this requirement because the failure of an entity to update the RAS database, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R9 does not address any of the identified areas; therefore, the FERC VRF G1 Discussion is not applicable.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with PRC-010-2 Requirement R6 and PRC-006-1 Requirement R6, which have an approved VRF of Lower.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A Lower VRF is appropriate for this requirement because the failure of an entity to update the RAS database, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30-calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30-calendar days but less than or equal to 60-calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60-calendar days but less than or equal to 90-calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90-calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

VSL Justifications for PRC-012-2, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-013-0, Requirement R1 and has VSLs comparable to the established Levels of Non-Compliance of that requirements, so there is no consequence of lowering the current level of compliance.

VSL Justifications for PRC-012-2, Requirement R9	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations**FERC VSL G3** Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is based upon a single violation, not a cumulative number of violations.The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

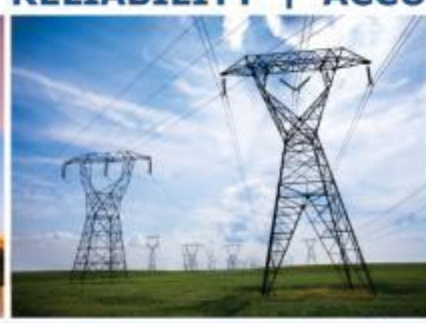
Reliability Standard PRC-012-2 Remedial Action Schemes Question & Answer Document

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

August 2015

RELIABILITY | ACCOUNTABILITY



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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
NERC Staff	Al McMeekin (Standards Developer)	NERC
NERC Staff	Lacey Ourso (Standards Developer)	NERC
NERC Staff	Andrew Wills (Associate Counsel)	NERC

Standards Announcement Reminder

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)
PRC-012-2

Initial Ballot and Non-binding Poll Open through October 5, 2015

Now Available

An initial ballot for **PRC-012-2 – Remedial Action Schemes** and a non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are open through **8 p.m. Eastern, Monday, October 5, 2015**.

Balloting

Members of the ballot pools associated with this project may log in and submit their votes for the standard and associated VRFs and VSLs by clicking here.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at EROhelpdesk@nerc.net (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and determine the next steps for the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)
PRC-012-2

Formal Comment Period Open through October 5, 2015
Ballot Pools Forming through September 18, 2015

Now Available

A 45-day formal comment period for draft one of **PRC-012-2 – Remedial Action Schemes** is open through **8 p.m. Eastern, Monday, October 5, 2015**.

Commenting
Use the electronic form to submit comments on the standard. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools
Ballot pools are being formed through **8 p.m. Eastern, Friday, September 18, 2015**. Registered Ballot Body members may join the ballot pools here.

Next Steps
An initial ballot for the standard and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **September 25 – October 5, 2015.**

For information on the Standards Development Process, refer to the Standard Processes Manual.

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Standards Announcement

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)
PRC-012-2

Initial Ballot and Non-binding Poll Results

Now Available

A formal comment period and initial ballot for **PRC-012-2 – Remedial Action Schemes** as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern, Monday, October 5, 2015.**

The standard did not receive sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides detailed results for the ballot and non-binding poll.

Ballot	Non-binding Poll
Quorum /Approval	Quorum/Supportive Opinions
83.70% / 48.10%	81.54% / 51.79%

Next Steps

The drafting team will consider all comments received during the formal comment and determine the next steps of the project.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/29)
Ballot Name: 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes PRC-012-2 IN 1 ST
Voting Start Date: 9/25/2015 12:01:00 AM
Voting End Date: 10/5/2015 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 267
Total Ballot Pool: 318
Quorum: 83.96
Weighted Segment Value: 48.11

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	87	1	33	0.516	31	0.484	0	8	15
Segment: 2	9	0.8	3	0.3	5	0.5	0	0	1
Segment: 3	72	1	28	0.549	23	0.451	0	6	15
Segment: 4	23	1	8	0.444	10	0.556	0	3	2
Segment: 5	71	1	25	0.49	26	0.51	0	10	10
Segment: 6	44	1	14	0.424	19	0.576	0	4	7
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	2	0.1	1	0.1	0	0	0	1	0
Segment: 9	1	0.1	0	0	1	0.1	0	0	0

Segment: 10	8	0.6	3	0.3	3	0.3	0	1	1
Totals:	318	6.7	116	3.224	118	3.476	0	33	51

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		None	N/A
1	Ameren - Ameren Services	Eric Scott		None	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Negative	Third-Party Comments
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas		Negative	Third-Party Comments

1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Donald Watkins		Negative	Comments Submitted
1	Bryan Texas Utilities	John Fontenot		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Negative	Comments Submitted
1	CPS Energy	Glenn Pressler		Abstain	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Negative	Comments Submitted
1	Duke Energy	Doug Hils		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass	Greg Davis	Affirmative	N/A

1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Negative	Third-Party Comments
1	IDACORP - Idaho Power Company	Molly Devine		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Meghan Ferguson	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		None	N/A
1	Lincoln Electric System	Doug Bantam		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Negative	Third-Party Comments
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Negative	Comments Submitted
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Abstain	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments

1	NB Power Corporation	Alan MacNaughton		Negative	Third-Party Comments
1	Nebraska Public Power District	Jamison Cawley		Negative	Comments Submitted
1	New York Power Authority	Salvatore Spagnolo		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Julaine Dyke		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Rod Kinard	Gul Khan	Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		Abstain	N/A
1	Peak Reliability	Jared Shakespeare		Negative	Comments Submitted
1	PHI - Potomac Electric Power Co.	David Thorne		Affirmative	N/A
1	Platte River Power Authority	John Collins		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General	John Walker		Affirmative	N/A

	Electric Co.				
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Denise Stevens		None	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Bertha Ellen Watkins		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A

1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Transmission Agency of Northern California	Eric Olson		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Negative	Third-Party Comments
1	VELCO -Vermont Electric Power Company, Inc.	Kim Moulton		None	N/A
1	Western Area Power Administration	sean erickson		None	N/A
1	Xcel Energy, Inc.	Dean Schiro		Negative	Comments Submitted
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Affirmative	N/A
2	California ISO	Richard Vine		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson	Elizabeth Axson	None	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Negative	Third-Party Comments
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	ISO New England, Inc.	Michael Puscas	John Pearson	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power	Charles Yeung		Affirmative	N/A

	Pool, Inc. (RTO)				
3	AEP	Michael DeLoach		None	N/A
3	Ameren - Ameren Services	David Jendras		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lisa Martin		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Pat Harrington		Affirmative	N/A
3	Beaches Energy Services	Steven Lancaster		Negative	Third-Party Comments
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Green Cove Springs	Mark Schultz		Negative	Third-Party Comments
3	City of Leesburg	Chris Adkins		Negative	Third-Party Comments
3	City of Redding	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Abstain	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs	Charles Morgan		Affirmative	N/A

	Utilities				
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Kent Kujala		Abstain	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Eversource Energy	Mark Kenny		Negative	Comments Submitted
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Negative	Comments Submitted
3	Florida Power & Light	Summer Esquerre		None	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Grand River Dam Authority	Jeff Wells		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Third-Party Comments
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Negative	Comments Submitted
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Mace Hunter		Negative	Third-Party Comments

3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Comments Submitted
3	New York Power Authority	David Rivera		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Blaine Dinwiddie		None	N/A
3	Pacific Gas and Electric Company	John Hagen		None	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Affirmative	N/A
3	Portland General Electric Co.	Thomas Ward		Affirmative	N/A

3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Negative	Comments Submitted
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None	N/A
3	Puget Sound Energy, Inc.	Andrea Basinski		Affirmative	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Salt River Project	John Coggins		None	N/A
3	Santee Cooper	James Poston		None	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		None	N/A
3	Seattle City Light	Dana Wheelock		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	James Frauen		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A

3	WEC Energy Group, Inc.	James Keller		Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith	Larry Heckert	None	N/A
4	Austin Energy	Tina Garvey		Abstain	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		Affirmative	N/A
4	City of Clewiston	Lynne Mila		Negative	Third-Party Comments
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Negative	Third-Party Comments
4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Abstain	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Negative	Comments Submitted
4	Keys Energy Services	Stanley Rzad		Negative	Third-Party Comments
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Abstain	N/A
4	Public Utility District No. 1 of Snohomish	John Martinsen		Affirmative	N/A

	County				
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		Affirmative	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Michael Ward		Negative	Comments Submitted
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Negative	Comments Submitted
4	Utility Services, Inc.	Brian Evans-Mongeon		Negative	Third-Party Comments
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Comments Submitted
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
5	Austin Energy	Jeanie Doty		Abstain	N/A
5	Avista - Avista Corporation	Steve Wenke		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Clement Ma		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Third-Party Comments

5	Bonneville Power Administration	Francis Halpin		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Calpine Corporation	Hamid Zakery		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City and County of San Francisco	Daniel Mason		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City of Redding	Paul Cummings	Bill Hughes	Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Randi Heise		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Dynegy Inc.	Dan Roethemeyer		Affirmative	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		None	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		Affirmative	N/A
5	Exelon	Vince Catania		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal	David Schumann		Negative	Comments

	Power Agency				Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Hydro-Qu?bec Production	Roger Dufresne		Abstain	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Negative	Third-Party Comments
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		None	N/A
5	Lower Colorado River Authority	Dixie Wells		Negative	Comments Submitted
5	Luminant - Luminant Generation Company LLC	Rick Terrill		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Abstain	N/A
5	NB Power Corporation	Rob Vance		Negative	Third-Party Comments
5	Nebraska Public Power District	Don Schmit		Negative	Comments Submitted
5	New York Power Authority	Wayne Sipperly		Negative	Third-Party Comments
5	NextEra Energy	Allen Schriver		Negative	Comments

					Submitted
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Affirmative	N/A
5	Oglethorpe Power Corporation	Teresa Czyz		None	N/A
5	Omaha Public Power District	Mahmood Safi		Abstain	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Abstain	N/A
5	Pacific Gas and Electric Company	Alex Chua		Abstain	N/A
5	Platte River Power Authority	Tyson Archie		Abstain	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	SCANA - South Carolina Electric and Gas Co.	Henry Delk		None	N/A
5	Seattle City Light	Mike Haynes		Negative	Comments Submitted
5	Seminole Electric	Brenda Atkins		Negative	Comments

	Cooperative, Inc.				Submitted
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Negative	Comments Submitted
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tennessee Valley Authority	Brandy Spraker	Dennis Chastain	Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Negative	Comments Submitted
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Negative	Comments Submitted
5	Xcel Energy, Inc.	Mark Castagneri		Negative	Comments Submitted
6	AEP - AEP Marketing	Edward P Cox		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Alex Spain		Negative	Comments Submitted
6	City of Redding	Marvin Briggs	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs	Shannon Fair		Affirmative	N/A

	Utilities				
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston	Kelly Silver	Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Louis Slade		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Earle Saunders		None	N/A
6	Exelon	Dave Carlson		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy		Negative	Third-Party Comments
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		Negative	Comments Submitted
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Negative	Comments Submitted
6	Muscatine Power and Water	Ryan Streck		Abstain	N/A
6	New York Power Authority	Shivaz Chopra		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and	Silvia Mitchell		Negative	Comments Submitted

	Light Co.				
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	Platte River Power Authority	Carol Ballantine		None	N/A
6	Portland General Electric Co.	Shawn Davis		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		None	N/A
6	Seattle City Light	Charles Freeman		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Negative	Comments Submitted
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Negative	Comments Submitted
6	Talen Energy Marketing, LLC	Elizabeth Davis		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	Scott Hoggatt		None	N/A
6	Xcel Energy, Inc.	Peter Colussy		Negative	Comments Submitted

7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Negative	Third-Party Comments
10	Florida Reliability Coordinating Council	Peter Heidrich		Abstain	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Negative	Comments Submitted
10	SERC Reliability Corporation	David Greene		None	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/29)
Ballot Name: 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes PRC-012-2 Non-binding Poll IN 1 NB
Voting Start Date: 9/25/2015 12:01:00 AM
Voting End Date: 10/5/2015 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 243
Total Ballot Pool: 297
Quorum: 81.82
Weighted Segment Value: 51.79

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	79	1	26	0.565	20	0.435	0	20	13
Segment: 2	9	0.4	1	0.1	3	0.3	0	3	2
Segment: 3	69	1	22	0.595	15	0.405	0	14	18
Segment: 4	22	1	7	0.467	8	0.533	0	5	2
Segment: 5	66	1	18	0.5	18	0.5	0	19	11
Segment: 6	40	1	10	0.435	13	0.565	0	10	7
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	2	0.1	1	0.1	0	0	0	1	0
Segment: 9	1	0.1	0	0	1	0.1	0	0	0

Segment: 10	8	0.4	1	0.1	3	0.3	0	3	1
Totals:	297	6.1	87	2.961	81	3.139	0	75	54

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		None	N/A
1	Ameren - Ameren Services	Eric Scott		None	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy	Terry Harbour		Affirmative	N/A

	Co.				
1	Bonneville Power Administration	Donald Watkins		Negative	Comments Submitted
1	Bryan Texas Utilities	John Fontenot		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Abstain	N/A
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Negative	Comments Submitted
1	CPS Energy	Glenn Pressler		Abstain	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass	Greg Davis	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Negative	Comments Submitted

1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Molly Devine		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Meghan Ferguson	Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		None	N/A
1	Lincoln Electric System	Doug Bantam		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Negative	Comments Submitted
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Abstain	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Negative	Comments Submitted

1	NiSource - Northern Indiana Public Service Co.	Julaine Dyke		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Abstain	N/A
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Rod Kinard	Gul Khan	Negative	Comments Submitted
1	Peak Reliability	Jared Shakespeare		Negative	Comments Submitted
1	Platte River Power Authority	John Collins		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	John Walker		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Abstain	N/A

1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		None	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	Transmission Agency of Northern California	Eric Olson		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Kim Moulton		None	N/A

1	Western Area Power Administration	sean erickson		None	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson	Elizabeth Axson	None	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	ISO New England, Inc.	Michael Puscas	John Pearson	None	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Michael DeLoach		None	N/A
3	Ameren - Ameren Services	David Jendras		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lisa Martin		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Pat Harrington		Abstain	N/A
3	Beaches Energy	Steven Lancaster		Negative	Comments

	Services				Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Green Cove Springs	Mark Schultz		Negative	Comments Submitted
3	City of Leesburg	Chris Adkins		Negative	Comments Submitted
3	City of Redding	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Abstain	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Abstain	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Kent Kujala		Abstain	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Eversource Energy	Mark Kenny		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal	Joe McKinney		Negative	Comments

	Power Agency				Submitted
3	Florida Power & Light	Summer Esquerre		None	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Grand River Dam Authority	Jeff Wells		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Comments Submitted
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Negative	Third-Party Comments
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Mace Hunter		Negative	Comments Submitted
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Negative	Comments Submitted
3	NiSource - Northern	Ramon Barany		Abstain	N/A

	Indiana Public Service Co.				
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Blaine Dinwiddie		None	N/A
3	Pacific Gas and Electric Company	John Hagen		None	N/A
3	Portland General Electric Co.	Thomas Ward		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None	N/A
3	Puget Sound Energy, Inc.	Andrea Basinski		Affirmative	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Salt River Project	John Coggins		None	N/A
3	Santee Cooper	James Poston		None	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		None	N/A
3	Seattle City Light	Dana Wheelock		Negative	Comments Submitted
3	Seminole Electric	James Frauen		Abstain	N/A

	Cooperative, Inc.				
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith	Larry Heckert	None	N/A
4	Austin Energy	Tina Garvey		Abstain	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		Affirmative	N/A
4	City of Clewiston	Lynne Mila		Negative	Comments Submitted
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Negative	Comments Submitted
4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Abstain	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Negative	Comments Submitted

4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Abstain	N/A
4	Keys Energy Services	Stanley Rzad		Negative	Comments Submitted
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		Affirmative	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Michael Ward		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Negative	Comments Submitted
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Comments Submitted
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
5	Austin Energy	Jeanie Doty		Abstain	N/A

5	Avista - Avista Corporation	Steve Wenke		Abstain	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Clement Ma		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Comments Submitted
5	Bonneville Power Administration	Francis Halpin		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Calpine Corporation	Hamid Zakery		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	City and County of San Francisco	Daniel Mason		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City of Redding	Paul Cummings	Bill Hughes	Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A

5	Dynegy Inc.	Dan Roethemeyer		Affirmative	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		None	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann		Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Hydro-Qu?bec Production	Roger Dufresne		Abstain	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Negative	Comments Submitted
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		None	N/A
5	Lower Colorado River Authority	Dixie Wells		Negative	Comments Submitted
5	Luminant - Luminant Generation Company LLC	Rick Terrill		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A

5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Negative	Comments Submitted
5	NextEra Energy	Allen Schriver		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Affirmative	N/A
5	Oglethorpe Power Corporation	Teresa Czyz		None	N/A
5	Omaha Public Power District	Mahmood Safi		Abstain	N/A
5	Pacific Gas and Electric Company	Alex Chua		Abstain	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	SCANA - South Carolina Electric and	Henry Delk		None	N/A

	Gas Co.				
5	Seattle City Light	Mike Haynes		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Negative	Comments Submitted
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tennessee Valley Authority	Brandy Spraker	Dennis Chastain	Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Abstain	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Negative	Comments Submitted
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		Affirmative	N/A
5	Xcel Energy, Inc.	Mark Castagneri		Negative	Comments Submitted
6	AEP - AEP Marketing	Edward P Cox		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Abstain	N/A
6	Bonneville Power Administration	Alex Spain		Negative	Comments Submitted
6	City of Redding	Marvin Briggs	Bill Hughes	Affirmative	N/A

6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston	Kelly Silver	Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Earle Saunders		None	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy		Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		Negative	Comments Submitted
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Negative	Comments Submitted
6	Muscatine Power and Water	Ryan Streck		Abstain	N/A
6	New York Power Authority	Shivaz Chopra		Negative	Comments Submitted
6	NextEra Energy - Florida Power and	Silvia Mitchell		Negative	Comments Submitted

	Light Co.				
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	Platte River Power Authority	Carol Ballantine		None	N/A
6	Portland General Electric Co.	Shawn Davis		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Abstain	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		None	N/A
6	Seattle City Light	Charles Freeman		None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Negative	Comments Submitted
6	Talen Energy Marketing, LLC	Elizabeth Davis		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A

9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Negative	Comments Submitted
10	Florida Reliability Coordinating Council	Peter Heidrich		Abstain	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Negative	Comments Submitted
10	SERC Reliability Corporation	David Greene		None	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Showing 1 to 297 of 297 entries

Previous 1 Next

Survey Report

Survey Details

Name 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes | PRC-012-2

Description

Start Date 8/20/2015

End Date 10/5/2015

Associated Ballots

2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes PRC-012-2 IN 1 ST

2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes PRC-012-2 Non-binding Poll IN 1 NB

Survey Questions

Requirements R1, R2, and R3 pertain to the submittal of Attachment 1 information to the Reliability Coordinator (RC) for the review of a RAS, the RC using Attachment 2 as a guide for performing the RAS review, and the RC approving the RAS prior to the RAS being placed in service. Question 1 is relevant to these activities.

1. RAS review and approval: Do you agree with the RAS review process outlined by Requirements R1, R2, and R3? If no, please provide the basis for your disagreement and an alternate proposal.

Yes

No

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

2. RAS Periodic Evaluations: Do you agree with the RAS planning evaluation process outlined by Requirement R4? If no, please provide the basis for your disagreement and an alternate proposal.

Yes

No

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

3. RAS Inadvertent Operation: Do you agree with Requirement 4 Part 4.3 and Attachment 1 which stipulates that RAS inadvertent operation due to a single component malfunction still satisfies the System performance requirements common to TPL-001-4 P1-P7 events listed in Parts 4.3.1-4.3.5? (Note that this requirement remains the same as PRC-012-0 R1.4 except for the allowance for designed-in security that would prevent RAS inadvertent operation for any single component malfunction). If no, please provide the basis for your disagreement and an alternate proposal.

Yes

No

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

4. RAS Single Component Failure: Do you agree with Requirement 4 Part 4.4 and Attachment 1 which stipulates that any RAS intended to satisfy System performance requirements in a TPL standard must still satisfy those requirements when experiencing a single component failure? (Note that this requirement remains unchanged from PRC-012-0 R1.3.) If no, please provide the basis for your disagreement and an alternate proposal.

Yes

No

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

5. Corrective Action Plans: Do you agree that the application of Requirements R6 and R7 would address the reliability objectives associated with CAPs? If no, please provide the basis for your disagreement and an alternate proposal.

Yes

No

6. Implementation Plan: Do you agree with the Implementation Plan? If no, please provide the basis for your disagreement and an alternate proposal.

Yes

No

7. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

Responses By Question

Requirements R1, R2, and R3 pertain to the submittal of Attachment 1 information to the Reliability Coordinator (RC) for the review of a RAS, the RC using Attachment 2 as a guide for performing the RAS review, and the RC approving the RAS prior to the RAS being placed in service. Question 1 is relevant to these activities.

1. RAS review and approval: Do you agree with the RAS review process outlined by Requirements R1, R2, and R3? If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer: No

Answer Comment:

The NSRF propose revising R2 to explicitly include the engagement of any applicable Planning Coordinators with wording like, “Each Reliability Coordinator . . . shall in conjunction with impacted Transmission Planners and Planning Coordinators . . .” The inclusion of Transmission Planners and Planning Coordinators is appropriate because RASs are ‘standing, automatic’ schemes that are evaluated primarily in the planning horizon and by Transmission Planners. In general, Reliability Coordinators do not have planning horizon analysis information or expertise.

We further recommend that M2 and M3 be modified such that acceptable evidence can be a Reliability Coordinator sponsored peer review by impacted entities.

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Oncor Electric Delivery believes that it is a good idea to have an independent party review any RAS. However, 90 days for the review seems more reasonable since they are just reviewing the scheme.

Additionally Oncor Electric Delivery believes the RAS information required in attachment 1 contains more than is necessary for a review and cannot always be obtained for every RAS. In fact, unless the RAS is an existing system during the review period there are usually no schematics to review so we do not believe it is appropriate to request schematic diagrams. The second bullet under General section I asks for “functionality of a new RAS”, which would be a relay functional diagram that depicts how the scheme works and that would be available during the review process.

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter	Segment
Ginette Lacasse	1,3,4,5,6
Entity	**Region(s)**
Seattle City Light	WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Group Information

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Voter Information

Voter	Segment
Chris Scanlon	1
Entity	**Region(s)**
Exelon	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment:

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

Document Name:

Likes: 0

Dislikes: 0

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer: No

Answer Comment:

a. R1 references “each RAS-entity shall submit…”, but there should only be one RAS-entity per RAS, is this correct?

b. The supplemental material of the Standard states that the RAS owners needs to select an RAS-entity or else the RC will select the RAS-entity. This language needs to be in the Standard if it’s going to be enforceable.

c. For the designation of the RAS-entity between different owners, will NERC/FERC/Regions require a CFR or JRO agreement? And what happens if one of the RAS owners is not a NERC registered entity, i.e., not a functional entity? Please describe what evidence needs to be provided to show designation of responsibility to the RAS-entity.

d. Also, most, if not all, new RASs are developed, studied, and reviewed within the long-term Planning Horizon by PCs and TPs. Modifications/retirements to existing RASs have the potential to be developed in the Operating Horizon; therefore, Seminole suggests that R1 be broken up into two requirements, one addressing modifications/retirements which would be specific to the “Operations Planning Horizon” and the second addressing “new” RASs specific to the “Long-term Planning Horizon” and applicable to PCs as well.

e. Can the drafting team define all of the components of an RAS so that “ownership” can be determined, i.e., what equipment makes up an RAS?

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

A. It is unclear why R3 is not structured consistent to R1 even though both requirements are prerequisites for achieving the same objective of "placing a new or functionally modified RAS in service or retiring an existing RAS". Suggest restructuring R3 as follows for clarity and consistency:
"Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, the RAS- entity shall address each issue identified by the RAS review (performed pursuant to Requirement R2) and obtain approval of the RAS from each reviewing Reliability Coordinator."

B. In R1, the RAS review falls within the purview of one or more RC's depending on "the area(s) where the RAS is located." What attributes define the location of a RAS? Should the RAS location comprise of only the station(s) where its remedial action logic processing device(s) is/are installed? Or would the RAS location also include the stations from where the various RAS inputs are telemetered to the logic processing device? Would it also include the station(s) at which the RAS output(s) – that is, remedial actions – are sent? Suggest that the standard provides clear guidance on what comprises the RAS location. Alternatively, suggest using a different RAS characteristic in R1 to avoid subjective and inconsistent interpretations of what comprises RAS location.

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment:

Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Document Name:

Likes: 0

Dislikes: 0

David Greene - SERC - 1,10 - SERC

Group Information

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Voter Information

Voter
David Greene

Segment
1,10

Entity
SERC

Region(s)
SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment:

ATC proposes revising R2 to explicitly include the engagement of any applicable Planning Coordinators with wording like, “Each Reliability Coordinator........ shall in conjunction with any Planning Coordinators ....” The inclusion of Planning Coordinators is appropriate because RASs are ‘standing, automatic’ schemes that are evaluated primarily in the planning horizon and by Transmission Planners. In general, Reliability Coordinators do not have planning horizon analysis information or expertise.

Document Name:

Likes: 0

Dislikes: 0

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: No

Answer Comment:

The Planning Coordinator is the correct function to determine where a RAS Scheme is required. The need for an RAS is determined from TPL studies and planned system performance. References to the Reliability Coordinator should be changed to Planning Coordinator. The NERC Functional Model defines the RC as being “The functional entity that maintains the Real- time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.” It is not responsible for the planning or installation of a Protection System. The NERC Functional Model does not support the RC as being the reviewer. The RC currently does not review nor have the authority to approve any other facility or protection system installation.

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

To remove possible confusion, “on a mutually agreed upon schedule” should be changed to “on a mutually agreed upon schedule between Reliability Coordinators and RAS-entities.”

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The Planning Coordinator is the correct function to determine where a RAS Scheme is required. The need for a RAS is determined from TPL studies and planned system performance. The standard correctly provides the RC with an opportunity to participate in providing opinion. The NERC Functional Model defines the RC as being “The functional entity that maintains the Real- time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.” It is not responsible for the planning or installing a Protection System. The NERC Functional Model does not support the RC as being the reviewer. The RC currently does not review nor have the authority to approve any other facility or Protection System installation. Clarification of R3 regarding approval of the RAS after all issues have been addressed should be made. The approval mentioned in R3 could be interpreted as an approval that each identified outstanding issue was addressed and not a complete formal approval of the RAS. If the RC is to perform the review, we suggest the following rewording for R3:

“Following the review performed pursuant to Requirement R2, the RAS- entity shall address each issue identified by the Reliability Coordinators participating in the review and obtain final approval(s) for the RAS from each Reliability Coordinator participating in the review, prior to placing a new or functionally modified RAS in service or retiring an existing RAS.”

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance, following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter	Segment
Pamela Hunter	1,3,5,6

Entity	Region(s)
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer: No

Answer Comment:

The owner of any protection scheme should be responsible for the correct design and implementation of the scheme – RAS or not. Just like the design of switching to create a blackstart cranking path by a TOP in EOP-005-2, Requirement 6 must be verified by that TOP, the owner of the RAS should be held to the same expectation that the RAS is correctly designed and implemented. If the SDT still believes that some sort of review is required, then that review should be limited in scope to reviewing the generic content of the RAS design and not delve into the technical depth identified in some parts of Attachment 2.

Using the criteria outline by the SDT in its recent webinar, in addition to the independence of the reviewer and geographic span, the team also mentioned "expertise in planning, protection, operations, equipment". The attributes of this expertise to the level expected do not currently exist in most RC organizations. RC's are primarily operating entities (and even then primarily in real-time) and not experts in planning (beyond the operating time frame), protection or equipment. Transmission Owners, Transmission Operators and Transmission Planners normally have that expertise. The FERC acknowledged the limited RC technical expertise in evaluating details of restoration plans in its Order 749, Paragraph 38 ("…basis on which a reliability coordinator rejects a restoration plan will necessarily be based on generic engineering criteria…”). The review of a RAS by an RC should not be held to a higher expectation due to similar limited expertise with the equipment and systems involved in a RAS.

The “flexibility” for the RC granted in the requirement to designate a third party would seem to immediately invalidate the original assumptions that the RC has the compelling capability to adequately perform the review while meeting the SDT’s characteristics of the reviewing entity. To allow this, while still requiring the RC to be responsible for the review, seems like an improper administrative burden and a potential compliance risk that the RC may assume because it had to find an entity more qualified than itself to perform the review. If an RC is not qualified to review all of the items in Attachment 2 then how can it be held responsible for the results of the review?

Regarding the designation of a third party reviewer, clarification needs to be made regarding what it means to “retain the responsibility for compliance.” Does this simply mean that the review takes place or that there is some implied resulting responsibility for the correct design and implementation that the RC is now accountable for.

Finally, also regarding the designation of a third party reviewer, is the term “third party” meant to be any entity not involved in the planning or implementation of the RAS?

The alterative to using the RC? Although there appears to be a movement to remove the RRO as a responsible entity from all standards, those organizations through their membership expertise and committee structures more closely match the characteristics stated by the SDT – expertise in planning/protection/operations/equipment, independence by virtue of the diversity of its members, wide area perspective, and continuity. If for some reason the SDT, believes that the RRO still should not be involved then an alternative could be the Planning Coordinator function which should have similar expertise to the Transmission Planners that are to specify/design a RAS per the functional model yet would have some independence which the SDT is looking for.

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

On the whole, Reclamation agrees with the RAS review process outlined in Requirements R1–R3. However, Reclamation believes that RAS-owners should also be listed in Attachment 1 and Attachment 3 and should be notified of all RAS-entity communications with the Reliability Coordinator (RC). Reclamation does not believe that the RAS-entity should be able to release technical information about a RAS-owner's equipment without the knowledge of the RAS-owner.

Document Name:

Likes: 0

Dislikes: 0

David Kiguel - David Kiguel - 8 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: No

Answer Comment:

Florida Power & Light appreciates the efforts of the Standard drafting Team in consolidating the existing RAS-related Standards into one Standard (PRC-012), however we disagree with the assertion that the Reliability Coordinator (RC) is the best choice to review RAS's for new or continued implementation. The RC is responsible for the operation rather than the planning of the BES. RAS design and approval is best performed at the planning level. The Planning Coordinator is responsible for coordinating transmission plans and protection systems and we believe more appropriate to review, approve and maintain the RAS database.

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Information

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter

Charles Yeung

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

Selected Answer: No

Answer Comment:

The ISO/RTO Council Standards Review Committee ("SRC") agrees that the RC should have to approve the use of RAS. Pursuant to the Functional Model, the RC does not have the authority to approve relay schemes. Nonetheless, it is important that the RC be informed of and understand how the RAS impacts the topology of its area of authority, identify and communicate any reliability issues to the RAS proponents, and coordinate with the RAS Entity regarding the in-service date and time of the RAS. We further recommend that M2 and M3 be modified such that acceptable evidence can be a Reliability Coordinator sponsored peer review with impacted Transmission Planners and Planning Coordinators.

Therefore, the SRC proposes that Requirement R3 be revised to:

R3. Following the review performed pursuant to Requirement R2, the RAS- entity shall address each identified issue and obtain concurrence from the Reliability

	Coordinator that all identified issues are resolved prior to placing a new or functionally modified RAS in service or retiring an existing RAS. While the SRC is not opposed to a guideline regarding the performance of RAS evaluations, Attachment 2 is overly prescriptive and does not allow for impacted entities to utilize their operational experience and engineering judgment. The SRC recommends that the introductory paragraph to Attachment 2 be revised to provide greater flexibility regarding RAS evaluations. The following revisions are suggested: The following checklist provides reliability related considerations for the Reliability Coordinator to consider for inclusion in its evaluation for each new or functionally modified2 RAS. The RC should utilize the checklist to determine those considerations that are applicable to the RAS evaluation being performed; however, RAS evaluations are not limited to the checklist items and the RC may request additional information on any reliability issue related to the RAS Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.
Document Name:	
Likes:	0
Dislikes:	0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

See comment in no. 7.

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment:

With regard to R1, the RAS entity is not typically qualified to provide some of the information required in Attachment 1, such as Sections II.3, II.4, II.5, and II.6. This information is typically developed by Planning Coordinator (PC) or Transmission Planner (TP). RAS owners typically only implement the RAS as functionally required by the PC or TP. It is noted that the Planning Coordinator is not listed as an applicable entity and should be.

The Planning Coordinator is the correct function to determine where a RAS Scheme is required. The need for an RAS is determined from TPL studies and planned system performance. The standard correctly provides the RC with an opportunity to participate in providing opinion. The NERC Functional Model defines the RC as being “The functional entity that maintains the Real- time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.” It is not responsible for the planning or installation of a Protection System. The NERC Functional Model

does not support the RC as being the reviewer. The RC currently does not review nor have the authority to approve any other facility or protection system installation. Clarification of R3 regarding approval of the RAS after all issues have been addressed should be made. The approval mentioned in R3 could be interpreted as an approval that each identified outstanding issue was addressed not complete formal approval of the RAS. If the RC is to perform the review, we suggest the following:

R3- Following the review performed pursuant to Requirement R2, the RAS- entity shall address each issue identified by the Reliability Coordinators participating in the review and obtain final approval(s) for the RAS from each Reliability Coordinator participating in the review, prior to placing a new or functionally modified RAS in service or retiring an existing RAS.

With regard to R3, some of the identified issues would be most appropriately addressed by the PC or TP, especially the items in Section II of Attachment 1. It is inappropriate for RAS entity to assume compliance responsibility for addressing each identified issue. The RAS owner for the RAS issues should be the responsible entity.

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter	Segment
Randi Heise	5
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer: No

Answer Comment:

As Dominion stated in its previous comments, we believe that RAS should be reviewed and approved in both the planning and operating horizons by designated entities within whose area(s) the Facility (ies) the RAS is designed to protect reside.

Dominion suggests the following specific changes to R1: Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS- entity shall submit the information identified in Attachment 1 for review to the Reliability Coordinator(s) **and Transmission Planner(s) within whose respective** area(s) the **Element(s) or Facility(ies)** for which the RAS is **designed to protect is (are)** located..

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter	Segment
John Seelke	1,3,5,6
Entity	**Region(s)**
PSEG	NPCC,RFC

Selected Answer: No

Answer Comment:

See the comment in #7.1. In addition, the Transmission Planner should be a required participant in developing Attachment 1 and at least be responsible for Section II in Attachment 1. Finally, the obligation in R3 that a RAS-entity address issues identified pursuant to R2 is incomplete. R3 should also place compliance obligations on the Transmission Planner and the RAS-owners to participate in addressing any issues under R3.

Document Name:

Likes: 4 PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Voter Information

Voter

Lee Pedowicz

Segment

10

Entity

Northeast Power Coordinating Council

Region(s)

NPCC

Selected Answer: No

Answer Comment:

Regarding Requirement R1, the RAS-entity is not typically qualified to provide some of the information required in Attachment 1, such as Sections II.3, II.4, II.5, and II.6. This information is typically developed by the Planning Coordinator (PC) or Transmission Planner (TP). RAS-owners typically only implement the RAS as functionally required by the PC or TP. The Planning Coordinator should be listed as an applicable entity.

The Planning Coordinator is the correct function to determine where a RAS Scheme is required. The need for a RAS is determined from TPL studies and planned system performance. The standard correctly provides the RC with an opportunity to participate in providing opinion. The NERC Functional Model defines the RC as being “The functional entity that maintains the Real- time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.” It is not responsible for the planning or installation of a Protection System. The NERC Functional Model does not support the RC as being the reviewer. The

RC currently does not review nor have the authority to approve any other facility or protection system installation. Clarification of R3 regarding approval of the RAS after all issues have been addressed should be made. The approval mentioned in R3 could be interpreted as an approval that each identified outstanding issue was addressed not complete formal approval of the RAS. If the RC is to perform the review, we suggest the following:

R3- Following the review performed pursuant to Requirement R2, the RAS- entity shall address each issue identified by the Reliability Coordinators participating in the review and obtain final approval(s) for the RAS from each Reliability Coordinator participating in the review, prior to placing a new or functionally modified RAS in service or retiring an existing RAS.

Regarding Requirement R3 some of the identified issues would be most appropriately addressed by the PC or TP, especially the items in Section II of Attachment 1 as mentioned earlier. It is inappropriate for the RAS-entity to assume compliance responsibility for addressing each identified issue. The RAS-owner for the RAS issues should be the responsible entity.

Document Name:

Likes: 0

Dislikes: 0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Answer Comment:

ERCOT supports the comments submitted by the ISO/RTO Council.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: No

Answer Comment:

PJM supports the comments submitted by the ISO/RTO Council.

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

R1, R2 and R3 do not differentiate between the functional aspects and design aspects of RAS. The functional requirements for a RAS, i.e. system conditions and triggering contingencies for which RAS is required as well as RAS actions to meet system performance requirement (as per TPL-001-4), are studied and identified by Transmission Planner and/or Planning Coordinator and not by the RAS owner/entity. The RAS owner/entity designs the RAS after TP or PC determines the functional requirements. The information listed in part II of attachment 1 is about functional requirements and can be provided by TP or PC. Most of the information listed in part I is repeat of part II. The rest, e.g., maps, one-line diagrams, in-service date, etc., can also be provided by TP or PC who determined the functional requirements. The information in part III, which is related to the RAS design, is provided by the RAS owner/entity. RAS owners typically only implement the RAS as functionally required by the PC or TP. It is noted that the Planning Coordinator is not listed as an applicable entity and should be. With regard to R3, some of the identified issues would be most appropriately addressed by the PC or TP, especially the items in Section II of Attachment 1.

We suggest that R1, R2 and R3 and the related attachments be split in two parts: a) functional aspects, where TP or PC will be required to determine the functional requirements of the RAS and provide relevant information to RC for review, and b) design aspects, where RAS owner/entity will be required to design the RAS to meet those functional requirements and provide relevant information to RC for review.

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer: No

Answer Comment:

The California ISO supports the comments of the ISO/RTO Standards Review Committee

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Gallo - Austin Energy - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dixie Wells - Lower Colorado River Authority - 5 -

Group Information

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Voter Information

Voter	Segment
Dixie Wells	5
Entity	**Region(s)**
Lower Colorado River Authority	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer: Yes

Answer Comment:

We agree with the checklist for the Reliability Coordinator to receive the proper information pertaining to the RAS and conducting a proper analysis. Additionally, we commend the drafting team for addressing the timing requirements in the Requirement R3 Rationale Box. We feel this will give the industry amply of enough time to address any issues identified by the Reliability Coordinator through their analysis.

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: No

Answer Comment:

Florida Power and Light appreciates the efforts of the Standard Drafting Team in consolidating the exsiting RAS-related Standards into one Standard - PRC-012-2, however we disagree with the assertion that the Reliability Coordinator (RC) is the best choice to review the RAS's for new and continued implementation. The RC is responsible for the operation rather than the planning of the BES. RAS design and approval is best done at the Planning level. The Planning Coordinator is responsible for coordinating transmission plans and protection systems and we believe more appropriate to review, approve, and maintain the RAS database.

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

In Requirement R3, the term “shall address” does not necessarily indicate the issue must be resolved as the Supplemental Material indicates. Texas RE recommends strengthening the requirement language to “shall resolve” or “shall implement”.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

1. RAS review should be conducted by the Planning Coordinator and not the Reliability Coordinator. Oversight of the wide-area in the planning horizon is the job of the Planning Coordinator. This will be a significant amount of extra work for the RCs who should be focused on near-term operational reliability.

2. R1 should state a time frame the data should be submitted to the RC, such as four month prior to implementation of the RAS. Otherwise, the burden will be placed on the RC to conduct the study on the RAS-entities schedule.

3. There is no requirement to notify impacted neighboring entities. When a RAS is implemented it can have a significant impact on neighboring entities. Neighboring entities need to have an opportunity to study the impact of the RAS.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

R1, R2 and R3 do not differentiate between the functional aspects and design aspects of RAS. The functional requirements for a RAS, i.e. system conditions and triggering contingencies for which RAS is required as well as RAS actions to meet system performance requirements (as per TPL-001-4), are studied and identified by the TP and/or PC and not by the RAS owner/entity. The RAS owner/entity designs the RAS after the TP or PC determines its functional requirements.   Therefore, the information listed in part II of attachment 1 is about functional requirements and can only be provided by a TP or PC in most instances.

Most of the information listed in Part I is repeated in Part II. The remaining information listed, e.g., maps, one-line diagrams, in-service date, etc., can also be provided by the TP or PC, who determines the functional requirements. The information in Part III, which is related to the RAS design, is provided by the RAS owner/entity.

Hydro One Networks Inc. suggests that R1, R2 and R3 and the related attachments be split in two parts: a) functional aspects, where the TP or PC will be required to determine the functional requirements of the RAS and provide relevant information to the RC for review, and b) design aspects, where the RAS owner/entity will be required to design the RAS to meet those functional requirements and provide relevant information to the RC for review.

In addition, it is inappropriate for the RAS entity to assume compliance responsibility for addressing each identified issue. The RAS owner for the RAS issues should be the responsible entity; this would be more in agreement with the assignment of accountabilities in R6.

Please also note our following comments with respect to relaxing the design review for a class of RAS.

Document Name:

Likes: 1 Hydro One Networks, Inc., 3, Malozewski Paul

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter	Segment
Carol Chinn	4
Entity	**Region(s)**
Florida Municipal Power Agency	

Selected Answer: No

Answer Comment:

R2 has an option of a four month schedule or a mutually agreed upon schedule. It is understood that setting a goal for a review within the operations time-frame is important, but it seems like the standard is trying to achieve two separate goals at once.

The first goal is to review the proposed change to determine whether it involves a CAP and identifies any current risks to reliability of the system which, as identified in the standard, might require use of System operating limits until the CAP is complete. This review needs to be completed quickly to minimize risk to the BES, but requires much less effort than a full review of the performance of the new RAS. In this instance four full-calendar months would seem to be too long of a time period.

The second goal is to complete the full review from a planning perspective. Each region already has a review and approval process in place. It seems arbitrary and unnecessary to impose the 4 month requirement rather than allowing the RC to follow a schedule or process it has already established. In this instance the four months would seem too short a time period in many cases due to the way these reviews are conducted (and by whom they are conducted) – so long as the risk to the BES reliability is already understood up-front, there is no reason to rush this portion of the work. In many cases, the RC in question may not possess the necessary staff / skills to perform what is required in Attachment 2, and may need to retain the services of others (consultants or perhaps area PCs or TPs), which will take time.

FMPA believes both issues could be resolved if R2 separated the near-term need to quickly assess BES reliability risk in the Operating Horizon from the long-term need to assess the details of the performance of the proposed scheme – particularly in cases where the proposed change is due to an identified issue with a subsequent CAP. Doing this first step on fast track would then allow each RC to define the schedule for the remaining review as per their regional practices.

Also, it would be beneficial to include all RAS-owners and their contact information in the RAS database.

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Voter Information

Voter

Brian Van Gheem

Segment

6

Entity

ACES Power Marketing

Region(s)

NA - Not Applicable

Selected Answer: No

Answer Comment:

(1) We question why the RC was selected as the reviewing entity in this context. RC System Operators are not required to be "familiar with" (Reliability Standard PRC-001) or "have knowledge of" (proposed Reliability Standard TOP-009) the purpose and limitations of a RAS. Moreover, after the RC has conducted its initial review (Requirement R2) and the RAS-entity has addressed the identified issues, there is no timeframe required for the RC to conduct a final review for approval. We suggest rewording Requirement R3 to require both the RAS-entity and the RC to address each identified issue within a mutually agreed upon timeframe and concluded by a final RC review. Documentation regarding

	an approval of the RC following its final review should then be listed as acceptable evidence in Measure M3. (2) We would also like the drafting team to state that an existing SPS will not need to go through the RC approval process even though the new definition of RAS could be applied as a new RAS device. The standard is unclear regarding which equipment will need to go through the RC approval process, existing SPS/RAS or new/changed RAS equipment? One possible solution is to state that all SPS and RAS equipment that are in service on the effective date of the proposed standard are considered RAS going forward and will not be required to go through the RC approval process.
Document Name:	
Likes:	0
Dislikes:	0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment:

BPA believes R2’s timeline of four-full-calendar months for RC review of RAS submission is too generous; it is inconsistent with regional practice. BPA proposes two weeks as appropriate, with less potential negative impact. The schedule should be short enough to accommodate the needs of the RAS owners and the “mutually agreed upon schedule” should apply if more time is needed.

Document Name:

Likes: 0

Dislikes: 0

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

2. RAS Periodic Evaluations: Do you agree with the RAS planning evaluation process outlined by Requirement R4? If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer: No

Answer Comment:

For R4, we propose revised wording to explicitly include any applicable Planning Coordinators with wording like, ". . . provide the results including any identified deficiencies to the RAS-owner(s), the reviewing Reliability Coordinators(s) and impacted Transmission Planners and Planning Coordinators."

Again, the inclusion of impacted Transmission Planners and Planning Coordinators is appropriate because these entities will generally have the best planning horizon information and expertise to review the evaluation.

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter	Segment
Ginette Lacasse	1,3,4,5,6
Entity	**Region(s)**
Seattle City Light	WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Group Information

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Voter Information

Voter	Segment
Chris Scanlon	1
Entity	**Region(s)**
Exelon	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment:

We agree the Transmission Planner should periodically evaluate each RAS but there needs to be a mechanism by which the RAS-owners are required to share the RAS information with the Transmission Planner.

Document Name:

Likes: 0

Dislikes: 0

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: No

Answer Comment:

The process is not clear about the responsibility for a RAS which is activated in multiple Transmission Planner areas such as WECC-1. The standard should clearly specify whose responsibility it is to perform technical studies. APS suggests the following language:

“For a RAS which is activated in multiple Transmission Planning areas, a mutually agreed upon Transmission Planner of one of the multiple Transmission Planning areas shall perform an evaluation of the RAS at least once every 60- full-calendar- months and provide the RAS- owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies.”

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer: No

Answer Comment:

a. For R4, can the TP merely provide the data to the RAS owners and the RAS-entity report the information to the RC?

b. In R4.2, please give additional detail as to what “adverse interactions” cover?

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: No

Answer Comment:

The rationale and/or technical guidance does not make a convincing case for why the periodic evaluation of RAS must be a planning horizon analysis, and thus suited to be performed by Transmission Planner. As currently drafted, R4 seems to have an underlying premise that the periodic evaluation needs to be performed for the near-term planning horizon, which makes the periodic evaluation akin to the typical (future year) planning studies performed by Transmission Planner. However, the rationale for R4 does not provide any justification for the above. In fact, performing a planning horizon analysis is inconsistent with, if not contradictory to, the following reliability need stated in the rationale “A periodic evaluation is needed because (material) changes in system topology or operating conditions that have occurred since the previous RAS evaluation – or initial review – was completed…” Doesn’t this imply that the periodic RAS evaluation is for past changes, not the future planned changes? If so, wouldn’t the periodic RAS evaluation be more akin to Operational Planning Analysis (OPA) in the operating horizon? Is there a reason why an OPA would not be able to comprehensively address items 4.1 – 4.4 required for periodic RAS evaluation? We note that the existing R4 rationale makes an inadequate claim that “items required to be addressed in the evaluation are planning analyses”, which is a weak basis for concluding that “consequently, the Transmission Planner is the functional entity best suited to perform the analyses.” Based on all the above reasons, we contend that the reliability objectives of periodic RAS evaluation are more effectively achieved based on an operating horizon analysis like OPA. Therefore, the periodic RAS evaluation lends itself better to be performed by the Transmission Operator (or perhaps even the Reliability Coordinator).

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment:

Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Document Name:

Likes: 0

Dislikes: 0

David Greene - SERC - 1,10 - SERC

Group Information

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Voter Information

Voter	Segment
David Greene	1,10
Entity	**Region(s)**
SERC	SERC

Selected Answer: Yes

Answer Comment:

Suggest clarifying in R4 that the evaluation is a technical evaluation as stated below:
Each Transmission Planner shall perform a **technical evaluation (planning analyses)** of each RAS within its planning area at least once every 60- full-calendar- months and provide the RAS- owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies.

Document Name:

Likes: 0

Dislikes: 0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment:

For R4, ATC proposes revising the wording to explicitly include any applicable Planning Coordinators with wording like, ". . . provide the results including any identified deficiencies to the RAS-owner(s), the reviewing Reliability Coordinators(s) and any applicable Planning Coordinators."

Again, the inclusion of Planning Coordinators is appropriate because the Transmission Planner evaluation will be for the planning horizon and Planning Coordinators will generally have the best information and expertise to review the evaluation.

Document Name:

Likes: 0

Dislikes: 0

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: No

Answer Comment:

The RAS-entity would be more appropriate to be specified in R4 instead of the RAS-owner

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The RAS-entity would be more appropriate to be specified in R4 instead of the RAS-owner.

Document Name:

Likes:	0
Dislikes:	0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter	Segment
Pamela Hunter	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Kiguel - David Kiguel - 8 -

Selected Answer: No

Answer Comment:

While generally supportive of this standard, I have concerns over assigning longer term assessment to Transmission Planner rather than to the Planning Coordinator.

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer: No

Answer Comment:

1.

   i. It is unclear why the Transmission Planner would provide results of the evaluation to each of the RAS- owner(s) and not the RAS-entity. A RAS typically operates as a single scheme and thus the RAS-entity can coordinate with all the RAS-owners regarding such evaluation results.

   ii. ReliabilityFirst currently reviews each SPS at least once every five years for compliance with our Regional Criteria in accordance with fill-in-the-blank NERC standard PRC-012, Requirement R1. ReliabilityFirst has concerns with the 60 month review cycle in Requirement R4 as there may be instances in which a SPS which was reviewed by RF in the 2000 timeframe could theoretically not be reviewed until the 2020 timeframe. ReliabilityFirst believes a potential gap of 10 years in between reviews may have reliability impact. In order to prevent such a potential gap, ReliabilityFirst recommends the following recommendation for consideration:

      a. Each Transmission Planner shall perform an evaluation of each RAS within its planning area at least once every 60- full- calendar- months **[since its last evaluation]** and provide the RAS- owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Information

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter

Charles Yeung

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

Selected Answer: No

Answer Comment:

Many Transmission Owner organizations also perform the transmission planning function and as such, are also registered as the Transmission Planners (for the assets that they own). The SRC believes that a proper, unbiased evaluation of RAS performance should be conducted by an entity that is not in the same organization as the TO and has a broader perspective, which is important because RAS's intended function and operational impact may affect more than one TO and TP. The SRC respectfully asserts that, given the importance of independence and a wide-area perspective, the Planning Coordinator is a more appropriate entity to perform Requirement R4 . The SRC therefore suggests replacing the TP with the PC or, at a minimum, requiring a review of results and provision of feedback by the Planning Coordinator to the Transmission Planner. This proposal is consistent with the basis for assigning R2 to the RC rather than the TOP.

Document Name:	
Likes:	0
Dislikes:	0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

See comment in no. 7.

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment:

The RAS-entity would be more appropriate to be specified in R4 instead of the RAS-owner.

The RAS-entity and the RAS-owner should be provided with the result of the review. The PC may be more appropriately qualified to review certain RAS than the TP.

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter	Segment
Randi Heise	5

Entity	Region(s)
Dominion - Dominion Resources, Inc.	

Selected Answer: Yes

Answer Comment:

Dominion suggests clarifying in R4 that the evaluation is a technical evaluation as stated below:

Each Transmission Planner shall perform a **technical** evaluation (planning analyses) evaluation of each RAS within its planning area at least once every 60- full- calendar- months and provide the RAS- owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies.

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter	Segment
John Seelke	1,3,5,6
Entity	**Region(s)**
PSEG	NPCC,RFC

Selected Answer: No

Answer Comment:

R4 should be modified to include a new part 4.5 that would require the Transmission Planner to identify any performance deficiencies in the RAS as well as alternatives for mitigating or correcting such deficiencies. The RAS-owners would not have the capability to identify alternatives for correcting deficiencies.

Document Name:

Likes: 4

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Voter Information

Voter	**Segment**
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer: No

Answer Comment:

It would be more appropriate to specify the RAS-entity in R4 instead of the RAS-owner.

The RAS-entity and the RAS-owner should be provided with the results of the review. The PC may be more appropriately qualified to review certain RAS than the TP. Consider revising R4 to read “Each Transmission Planner shall evaluate…”.

Add wording to the Rationale for Requirement R4 to clarify that the intent is not to evaluate all RAS at the same time, but that each RAS is to be evaluated on a 60 full calendar month cycle.

Would the Planning Coordinator ever perform this evaluation instead of the Transmission Planner?

Document Name:

Likes:	0
Dislikes:	0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Answer Comment:

ERCOT supports the comments submitted by the ISO/RTO Council.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: No

Answer Comment:

PJM supports the comments submitted by the ISO/RTO Council.

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: No

Answer Comment:

How would a scenario be addressed in which a RAS spans two or more Transmission Planner areas?

Document Name:

Likes: 0

Dislikes: 0

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer: No

Answer Comment:

TANC has concerns with the current language in R4 because appears to assume that a RAS exists within a single planning area. NERC has not defined the term “planning area”, which creates ambiguity in the requirement’s language that states “Each Transmission Planner shall perform an evaluation of each RAS within its planning area.” This ambiguity is further compounded in circumstances where a single RAS exists within the footprints of multiple Transmission Planners (and Planning Coordinators). In such cases, it is unclear which Transmission Planners associated with the multiple RAS-owners for a single RAS would have responsibility in accordance with this standard.

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

We generally agree with the process outlined by R4, but reiterate our comment that the Planning Coordinator, NOT the TP, should the entity responsible for this requirement.

Many Transmission Owner organizations also perform the transmission planning function and as such, are also registered as the Transmission Planners (for the assets that they own). A proper and unbiased evaluation of the RAS performance should be conducted by an entity that is not in the same organization as the TO and has a wider perspective than the TO and TP. And since the RAS intended function its operational impact may affect more than one TOs and TPs, a PC is the most appropriate entity to perform this task than the TP, both from an independence and a wide area perspectives. We therefore suggest replacing the TP with the PC. This proposal is consistent with the basis for assigning R2 to the RC rather than the TOP.

	The RAS-entity and the RAS-owner should be provided with the result of the review. The PC may be more appropriately qualified to review certain RAS than the TP.
Document Name:	
Likes:	0
Dislikes:	0

Richard Vine - California ISO - 2 -	
Selected Answer:	No
Answer Comment:	The California ISO supports the comments of the ISO/RTO Standards Review Committee
Document Name:	
Likes:	0
Dislikes:	0

Jamison Cawley - Nebraska Public Power District - 1 -	
Selected Answer:	Yes
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Andrew Gallo - Austin Energy - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dixie Wells - Lower Colorado River Authority - 5 -

Group Information

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Voter Information

Voter	Segment
Dixie Wells	5
Entity	**Region(s)**
Lower Colorado River Authority	

Selected Answer: No

Answer Comment:

To address existing entity NERC registration in the ERCOT region, “Transmission Planner” should be replaced with “Transmission Planner (in the ERCOT Region this applies to the Planning Authority and /or Reliability Coordinator.)”

R4. Each Transmission Planner (in the ERCOT Region this applies to the Planning Authority and /or Reliability Coordinator) shall perform an evaluation of

	each RAS within its planning area at least once every 60- full- calendar- months and provide the RAS- owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether: *[Violation Risk Factor: Medium] [Time Horizon: Long- term Planning]*
Document Name:	
Likes:	0
Dislikes:	0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer: Yes

Answer Comment:

We feel that the Transmission Planner also conducting an analysis will help address changes to the RAS which could impact the BES. Additionally, we like the fact that the analysis can be performed earlier if changes to the systems topology or system operating conditions has a potential impact on the BES (as mentioned in the second paragraph of the Rationale Box for Requirement R4).

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE asks the drafting team to consider adding the Planning Coordinator to Requirement R4 for instances where a RAS covers multiple Transmission Planner areas. The current practice the ERCOT region is ERCOT conducts the 5-year review of each RAS; however, ERCOT is the Planning Coordinator, not a Transmission Planner.

Texas RE asks the drafting about the term “60-full-calendar-months” in Requirements R4 and R6. The term is not defined and is not consistent with other standards and requirements. PRC-006 indicates five years, PRC-010-1 indicates 60 calendar months, and PRC-014 indicates five years. Texas RE recommends not introducing new terms and to be as consistent as possible. Is the SDT defining a “full calendar month” or “calendar year”? The RSAW is not the place to define a new term and the definition is different than terms used in PRC-005. This definition is misleading to those reviewing the document and could potentially exacerbate reliability issues nearly seven years based on the “definition” provided in the Note to Auditor section of R4 in the RSAW.

The intent of Requirement R9 should be to update once per year not once per 729 days (2 years minus 1 day) which would be allowable by the definition of full calendar year as stated in the RSAW.

Texas RE recommends defining the term “planning area”. It should be prescriptive enough to include GOs and DPs that are RAS-owners, i.e. generator owners or distribution providers that own all or part of a RAS. In Requirement R4, by default a Generator Owner or Distribution Provider owned RAS would be within a Transmission Planners planning area, correct? Please confirm or give specifics as to why a GO or DP owned RAS would not be within a Transmission Planners planning area.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The RAS owner must review the RASs in R4, R5, R6. Nowhere does it give the reviewing Reliability Coordinator the authority to dispute the evaluation in R4, dispute the analysis in R5, and require changes to the corrective action plan in R6. RC is just provided the results of analysis but is not given any authority to do anything with them.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

Although Hydro One Networks Inc. agrees with the evaluation process, we emphasize (as described above in Q1) that the evaluation of each new RAS must also be required from the TP or PC before the RAS is approved and implemented by the RAS owner/entity. We recognize that it is inconsistent to require the initial assessment of a RAS from a RAS owner/entity (in R1), and the subsequent/periodic assessments from a TP (in R4).

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter	Segment
Carol Chinn	4
Entity	**Region(s)**
Florida Municipal Power Agency	

Selected Answer: Yes

Answer Comment:

Recommend changing 60 full calendar months to 5 calendar years, to allow the RAS evaluation to fit within the annual Planning Assessment process which may vary from year to year.

Document Name:

Likes:	0
Dislikes:	0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Voter Information

Voter	Segment
Brian Van Gheem	6
Entity	**Region(s)**
ACES Power Marketing	NA - Not Applicable

Selected Answer: No

Answer Comment:

(1) We believe 60 calendar months is an appropriate amount of time to conduct RAS periodic evaluations. However, we do not believe the TP has sufficient visibility outside of its area to determine if the BES will remain stable or the occurrence of a Cascading outage will be minimized following the inadvertent operation of a RAS from any single RAS component malfunction. These “wide-area” views are only available to the PC. We believe the requirement should be rewritten to include the PC as an applicable entity for these technical evaluations.

	(2) We have concerns that the requirement does not identify what events will trigger when the clock begins on the 60 calendar month timeframe. We ask the SDT to clarify when the clock starts for these periodic evaluations – is it after the initial installation, after the latest modification to RAS functionality, or following a response to a CAP?
Document Name:	
Likes:	0
Dislikes:	0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

3. RAS Inadvertent Operation: Do you agree with Requirement 4 Part 4.3 and Attachment 1 which stipulates that RAS inadvertent operation due to a single component malfunction still satisfies the System performance requirements common to TPL-001-4 P1-P7 events listed in Parts 4.3.1-4.3.5? (Note that this requirement remains the same as PRC-012-0 R1.4 except for the allowance for designed-in security that would prevent RAS inadvertent operation for any single component malfunction). If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:

Clarity is needed in R4 as to exactly what the trigger is for the 60-full-calendar-months periodic review. Is it tied, perhaps, to the in-service status? In addition, rather than a 60 full month periodic review, AEP suggests a “5 calendar year” review. This would allow flexibility for an entity to integrate this work into its annual planning cycle.

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter

Ginette Lacasse

Segment

1,3,4,5,6

Entity

Seattle City Light

Region(s)

WECC

Selected Answer: No

Answer Comment:

Needs further clarification. The Transmission Planner or the group that *owns* the RAS should be responsible for the evaluation, coordination and testing of the RAS.

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Group Information

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Voter Information

Voter	Segment
Chris Scanlon	1
Entity	**Region(s)**
Exelon	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: No

Answer Comment:

Recommend deleting Part 4.3 since we find it hard to conceive how the inadvertent operation of RAS can result in unacceptable system performance when the primary motivation for installing any RAS is to achieve acceptable system performance. We acknowledge that inadvertent RAS operation is undesirable, but we also recognize that it is fundamentally the same as a RAS misoperation. And therefore, any adverse reliability impact due to inadvertent RAS operation would get addressed in R5 during RAS operational performance analysis. Consequently, we do not see any reliability risk, and thus no associated compelling need, to identify the potentially unacceptable system performance based on simulations/analyses performed for periodic RAS evaluation using models that reflect “typical” rather than actual operating conditions. Although we agree with the goal of a robust RAS design that is not susceptible to RAS misoperation caused by the malfunction of a single component, we also believe this objective is effectively accomplished by any corrective action plan spawned by the RAS operational performance analysis in R5.

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment:

Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Document Name:

Likes: 0

Dislikes: 0

David Greene - SERC - 1,10 - SERC

Group Information

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Voter Information

Voter	Segment
David Greene	1,10
Entity	**Region(s)**
SERC	SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: No

Answer Comment:

Part 4.3 addresses inadvertent operation and addresses security of the RAS. This is important however and we suggest that only 4.3.1 and 4.3.2 as well as controlling system separation are the only aspects that are needed. In Attachment 2 we agree that inadvertent operation needs to be understood however if that inadvertent operation does not cause one of the three significant adverse impacts to the reliability of the BES then the RAS should not be subject to additional requirements which likely will only have a localized effect. The addition of this language in R 4.3.3, 4.3.4, and 4.3.5 unnecessarily may result in local RAS to have increased design complexity, additional components which may increase the likelihood of misoperation (decreasing the reliability of the RAS) and excessive costs. We suggest the SDT consider that all RAS which have a wider impact, whose inadvertent operation could result in Cascading, System

Separation or instability be subject to this standard and its design requirements. To place these requirements as written on all RAS would be of little or no benefit to achieving an adequate level of reliability on the BES and based on this we would characterize this as placing a requirement such as those removed by Paragraph 81 in the standard. Furthermore, this could actually be a detriment to the reliable operation of a local RAS subjecting it to unnecessary additional design requirements.

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

Consider adding 4.3.6 “Frequency Trigger Limits (FTLs) shall be within acceptable limits as established”

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Part 4.3 addresses inadvertent operation and addresses security of the RAS. This is important; however, we suggest that 4.3.1, 4.3.2, and controlling system separation should be the only aspects that are needed. We do not understand the intent of 4.3.3 “applicable facility ratings.” Is this normal, emergency, DAL (drastic action limit), etc.? In Attachment 2, we agree that inadvertent operation needs to be understood however if that inadvertent operation does not cause one of the three significant adverse impacts to the reliability of the BES, then the RAS should not be subject to additional requirements when the inadvertent operation likely will only have a localized effect. The addition of this unnecessary language in R 4.3.3, 4.3.4, and 4.3.5 may result in local RAS having increased design complexity, additional components that may increase the likelihood of misoperation (decreasing the reliability of the RAS) and excessive costs. We suggest the SDT consider that all RAS that have a wider impact, whose inadvertent operation could result in Cascading, System Separation, or instability, be subject to this standard and its design requirements. To place these requirements as written on all RAS would be of little or no benefit to achieving an adequate level of reliability on the BES and based on this we would characterize this as a Paragraph 81 requirement in the standard. Furthermore, this could actually be a detriment to the reliable operation of a local RAS, subjecting it to unnecessary additional design requirements.

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter	Segment
Pamela Hunter	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Kiguel - David Kiguel - 8 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Information

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter

Charles Yeung

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

See comment in no. 7.

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment:

Part 4.3 addresses inadvertent operation and addresses security of the RAS. This is important however we suggest that only 4.3.1 and 4.3.2 as well as controlling system separation are the only aspects that are needed. We do not understand the intent of 4.3.3 “applicable facility ratings”. Is this normal, emergency, DAL (drastic action limit), etc.? In Attachment 2 we agree that inadvertent operation needs to be understood however if that inadvertent operation does not cause one of the three significant adverse impacts to the reliability of the BES then the RAS should not be subject to additional requirements which likely will only have a localized effect. The addition of this language in R 4.3.3, 4.3.4, and 4.3.5 unnecessarily may result in local RAS to have increased design complexity, additional components which may increase the likelihood of misoperation (decreasing the reliability of the RAS) and excessive costs. We suggest the SDT consider that all RAS which have a wider impact, whose inadvertent operation could result in Cascading, System Separation or instability be subject to this standard and its design requirements. To place these requirements as written on all RAS would be of little or no benefit to achieving an adequate level of reliability on the BES and based on this we would characterize this as placing a Paragraph 81 requirement in the standard. Furthermore, this could actually be a detriment to the reliable operation of a local RAS subjecting it to unnecessary additional design requirements.

Document Name:

Likes:	0
Dislikes:	0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter	Segment
Randi Heise	5

Entity	Region(s)
Dominion - Dominion Resources, Inc.	

Selected Answer: No

Answer Comment:

Dominion concurs with the idea of an inadvertent operations test; however R4.3.5 transient voltage response should not be part of that test. Preventing FIDVR is only necessary to prevent cascading due to motor stalling (an unlikely outcome) which is addressed under R4.3.2. Dominion believes that slow transient voltage response that does not lead to cascading and is a customer power quality issue and not a reliability issue.

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter	Segment
John Seelke	1,3,5,6
Entity	**Region(s)**
PSEG	NPCC,RFC

Selected Answer:

Answer Comment:

No comment.

Document Name:

Likes: 4

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Voter Information

Voter

Lee Pedowicz

Segment

10

Entity

Northeast Power Coordinating Council

Region(s)

NPCC

Selected Answer: No

Answer Comment:

Part 4.3 addresses inadvertent operation and addresses security of the RAS. This is important. However, we suggest that only sub-Parts 4.3.1 and 4.3.2 as well as controlling system separation are the only aspects that are needed. We do not understand the intent of sub-Part 4.3.3 “applicable facility ratings”. Is this normal, emergency, DAL (drastic action limit), etc.? In Attachment 2 we agree that inadvertent operation needs to be understood. However, if that inadvertent operation does not cause one of the three significant adverse impacts to the reliability of the BES then the RAS should not be subject to additional requirements which likely will only have a localized effect. The addition of this language in sub-Parts 4.3.3, 4.3.4, and 4.3.5 unnecessarily may result in local RAS to have increased design complexity, additional components which may increase the likelihood of misoperation (decreasing the reliability of the RAS) and excessive costs. We suggest the SDT consider that all RAS that have a wider impact, those whose inadvertent operation could result in Cascading, System Separation or instability be subject to

	this standard and its design requirements. To place these requirements as written on all RAS would be of little or no benefit to achieving an adequate level of reliability on the BES, and based on this we would characterize this as placing a Paragraph 81 requirement in the standard. Furthermore, this could actually be a detriment to the reliable operation of a local RAS subjecting it to unnecessary additional design requirements.
Document Name:	
Likes:	0
Dislikes:	0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

ERCOT supports the comments submitted by the ISO/RTO Council.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

At the present time there are RAS in service that have a limited local impact. To universally apply the same design criteria to all RAS regardless of their impact on BES in case of an inadvertent operation may have no cost benefit in the case of the RAS installed to address local problems.

We propose the following to be included in the standard:

An inadvertent operation in the RAS, when the RAS is intended to operate, does not result in any of the following conditions on the BES:

1. Cascading
2. Uncontrolled System Separation
3. Instability

When the criteria mentioned above is not met a secure design will be required.

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer: Yes

Answer Comment:

The California ISO supports the comments of the ISO/RTO Standards Review Committee

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Gallo - Austin Energy - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dixie Wells - Lower Colorado River Authority - 5 -

Group Information

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Voter Information

Voter	**Segment**
Dixie Wells	5
Entity	**Region(s)**
Lower Colorado River Authority	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

The SDT may want to consider adding “Applicable System Operating Limits shall not be exceeded” as a sub-bullet to Requirement R4.3.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter	Segment
Carol Chinn	4
Entity	**Region(s)**
Florida Municipal Power Agency	

Selected Answer: No

Answer Comment:

FMPA agrees with the intent of R4.3 – that construction of devices/systems as an integral part of the BES should be held to same standards as construction of physical facilities. However, we believe there is a problem with the wording of the first sentence. It is possible to read the first sentence to be requiring that inadvertent operation of the RAS due to a single component malfunction be studied as a planning event regardless of whether the system is designed to prevent such an event from occurring. FMPA believes the intent of the language

	is that items 4.3.1 through 4.3.5 only apply if single component malfunction does actually produce an operation of the RAS. If this were not true (e.g. if the language in R4.3 was requiring the study of the inadvertent RAS operation against the criteria in 4.3.1 through 4.3.5 regardless of whether a single component malfunction could actually cause the RAS to operate), the language would essentially be requiring that TPL-001-4 Planning Event criteria be applied to what amounts to an Extreme Event. This is partly because of the use of the term "malfunction" as opposed to "failure". This is not consistent with TPL-001-4 which refers to protection system "failures". This is an important distinction because typically protection systems are designed such that if a component fails, it does so without issuing a false trip. A malfunction can be interpreted to mean a large number of absurdly unlikely things which are over and above the level of rigor required by TPL-001-4. FMPA understands that the SDT desired to consider the use of non-"protection system" control devices using this standard, but the language as written does not allow those entities that are using protective devices to take credit for basic design principles such as redundancy. Suggest either expressly allowing entities to take credit for redundancy, switching to using the term "failure" or both.
Document Name:	
Likes:	0
Dislikes:	0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Voter Information

Voter

Brian Van Gheem

Segment

6

Entity

ACES Power Marketing

Region(s)

NA - Not Applicable

Selected Answer: No

Answer Comment:

Certain aspects of the TPL-001-4 P1-P7 events identify actions under a steady state or a stability assessment. We have concerns that applicable Facility Rating exceedances and BES voltages deviations, as identified with TPL-001-4, are only applicable under steady state conditions. We recommend the SDT modify Requirement R4 to identify these references within the context of a steady state assessment, instead of a transient state, to align with existing NERC standards.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

4. RAS Single Component Failure: Do you agree with Requirement 4 Part 4.4 and Attachment 1 which stipulates that any RAS intended to satisfy System performance requirements in a TPL standard must still satisfy those requirements when experiencing a single component failure? (Note that this requirement remains unchanged from PRC-012-0 R1.3.) If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer: No

Answer Comment:

The NSRF recommends two modifications to Part 4.4.:

One modification is to explicitly include “option c” in the Implementation section of the Supplemental Material associated with the Standard. The revised wording could be, “A single component failure in RAS, when the RAS is intended to operate, or alternative automatic actions back up the failures of single RAS components . . .” Including text about the alternative option in the standard, rather than the Supplemental Material would assure that it cannot be dismissed by an auditor.

The other modification is to remove the unnecessary linking of R4.4 to TPL-001-4 performance requirements with linking to the performance requirements already expressed in R4.3 of PRC-002-2. The revised wording could be, “. . . satisfies the same performance criteria given in Part 4.3”. This change makes the performance requirements of Part 4.3 and Part 4.4 consistent with each other and subject to changes in the PRC-012-2, rather than independent changes in another NERC standard.

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter

Ginette Lacasse

Segment

1,3,4,5,6

Entity

Seattle City Light

Region(s)

WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Group Information

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Voter Information

Voter	Segment
Chris Scanlon	1
Entity	**Region(s)**
Exelon	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment:

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

Document Name:

Likes: 0

Dislikes: 0

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: No

Answer Comment:

We do not agree that the “single component failure” requirement should apply to **all** RAS installed to satisfy TPL performance requirements, by completely disregarding the severity of adverse system impact resulting from the RAS failure to operate. In other words, we are advocating that due regard be given to the RAS classifications/types existing in NPCC, WECC and TRE regions, as well as the recommended RAS/SPS classifications in the SAMS-SPCS white paper. Using the RAS nomenclature proposed in the white paper, we recommend that the “single component failure” requirement be limited to Type PS (Planning Significant) schemes only. Excluding the Type PL schemes, like the accepted exclusion for “safety net” (Type ES/EL) schemes, does not necessarily compromise Adequate Level of Reliability in the BES. We recognize that this approach will require judicious selection of the demarcation criteria between

	Significant (Wide Area) versus Limited (Local) schemes – however, the existing NPCC and/or WECC demarcation criteria may serve as a reasonably good starting point. Lastly, we disagree with the claim that Part 4.4 remains unchanged from the existing R1.3 in PRC-012-0 – although both may have essentially the same verbiage, the context and the scope of applicability are widely different. While the existing R1.3 may be rightly interpreted to allow discretion to the RRO to determine which RAS/SPS "Types" must be subject to the more robust design that is not degraded by "single component failure", Part 4.4 takes away that discretion by virtue of being a continent-wide standard. There is no factual evidence to suggest that the failure-to-operate of any Local/Limited RAS has resulted in unacceptable/adverse BES performance to warrant "raising the bar" on applicability of "single component failure" requirement.
Document Name:	
Likes:	0
Dislikes:	0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:	Yes
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment:

Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Document Name:

Likes: 0

Dislikes: 0

David Greene - SERC - 1,10 - SERC

Group Information

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Voter Information

Voter

David Greene

Segment

1,10

Entity

SERC

Region(s)

SERC

Selected Answer: Yes

Answer Comment:

Suggest adding clarity to indicate the intent of R4 is not to evaluate the performance of
the RAS “following” an inadvertent operation since this is covered by R5. The below statement from
the rationale for R4 can be misinterpreted to imply R4 requires the Transmission Planner to perform
a technical evaluation “following” an inadvertent operation.

Copied from Rationale for R4:
*The purpose of a periodic RAS evaluation is to verify the continued effectiveness and coordination
of the RAS, as well as to verify that requirements for BES performance following an inadvertent RAS
operation or a single component failure in the RAS continues to be satisfied.*

Document Name:

Likes: 0

Dislikes:	0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment:

ATC recommends two modifications to Part 4.4.

One modification is to explicitly include “option c” in the Implementation section of the Supplemental Material associated with the Standard. The revised wording could be, “A single component failure in RAS, when the RAS is intended to operate, or alternative automatic actions back up the failures of single RAS components . . .” Including text about the alternative option in the standard, rather than the Supplemental Material would assure that it cannot be dismissed by an auditor.

The other modification is to remove the unnecessary linking of R4.4 to TPL-001-4 performance requirements with linking to the performance requirements already expressed in R4.3 of PRC-002-2. The revised wording could be, “. . . satisfies the same performance criteria given in Part 4.3”. This change makes the performance requirements of Part 4.3 and Part 4.4 consistent with each other and subject to changes in the PRC-012-2, rather than independent changes in another NERC standard.

Document Name:

Likes: 0

Dislikes: 0

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: No

Answer Comment:

Requirement R4 Part 4.4 is problematic for a number of reasons. First, placing this requirement on the Transmission Planner does not conform to the responsibilities or abilities of the Transmission Planner. While the TP may have some familiarity with the design of the RAS or with the Operating Procedures which may be in place, it does not know or need to know the specifics of a single component failure, just the ramification of an overall RAS operation failure or inadvertent operation. Currently, the unapproved standard PRC-012-0 and -1 R1.3 contains a single component failure design requirement which is currently unapproved by FERC and the applicable governmental authorities in Canada. When these standards were approved by the NERC BOT there was no NERC BES definition nor was there an approved definition of what a RAS is. We believe that had the full implication of the costs to be borne by the industry been recognized and subsequent minimal or no reliability benefit associated with meeting that requirement for local impact only schemes, the standard would not have been approved. Further, the System Protection Coordination Subcommittee of NERC had specifically noted and suggested that 4 types of RAS are on the BES. Two of these were local and these categories were developed to afford the SDT to tailor specific and appropriate reliability and security requirements on these local type schemes. To broadly apply these more stringent requirements to all RAS on the new BES with the new RAS definition has little cost benefit. In addition, the existing PRC-012-0 and -1 only require a single component failure review and design requirement at the time of review. PRC-014-0 and -1, which are the SPS/RAS assessment standards currently do not require the Transmission Planner to include a requirement such as Requirement R4 Part 4.4 in their periodic assessment.

The regions should each have a process for ensuring the reliability of the BES and that the necessary level of reliability and security had been met at the time of approval. Furthermore, misoperations studies have not indicated that there is a reliability need to incorporate single component failure design into local systems. These local RAS which do not meet the requirement would need to be redesigned, outages taken and then have their revisions made to come into compliance. This, in and of itself would represent a risk to the operation and reliability of the BES.

Requirement R4 Part 4.4 currently states;

"4.4 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 is designed."

We suggest Part 4.4 be removed. However, if the SDT is unwilling to remove it we would propose the following:

4.4 A single component failure in the RAS, when the RAS is intended to operate,

does not result in any of the following conditions on the BES:

- Cascading
- Uncontrolled System Separation
- Instability

The above modification would provide the necessary level of security and reliability to the BES. Ensuring that RAS installed on the BES or to meet TPL requirements would only be required when the RAS operation is critical and any inadvertent operation results in a significant impact to the BES.

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

Please affirm this understanding: For single component failure, a RAS must still satisfy System performance requirements.

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Requirement R4 Part 4.4 is problematic for a number of reasons. First, placing this requirement on the Transmission Planner does not conform to the responsibilities or abilities of the Transmission Planner. While the TP may have some familiarity with the design of the RAS or with the Operating Procedures in place, they do not know or need to know the specifics of a single component failure. The TP just needs to know the ramifications of an overall RAS operation failure or inadvertent operation. Currently, standards PRC-012-0 and PRC-012-1 R1.3 contain a single component failure design requirement. When these standards were approved by the NERC BOT, there was no NERC BES definition nor was there an approved definition of a RAS. We believe that had the full implication of the costs to be borne by the industry and the subsequent minimal or no reliability benefit associated with this (local impact only schemes) had been recognized, the standard would not have been approved by the NERC BOT. Further, the System Protection Coordination Subcommittee of NERC had specifically noted and suggested that 4 types of RAS are on the BES. Two of these types were local and these categories were developed to allow the SDT to tailor specific and appropriate reliability and security requirements on these local type schemes. To broadly apply these more stringent requirements to all RAS on the new BES with the new RAS definition has no cost benefit. In addition, PRC-012-0 and PRC-012-1 only require a single component failure review and design requirement at the time of review. PRC-014-0 and PRC-014-1, which are the SPS/RAS assessment standards, currently do not require the Transmission Planner to include a requirement such as Requirement R4 Part 4.4 in their periodic assessment. The SDT has gone, in our view, unnecessarily beyond the intent of the current standards in this regard.

In addition, it should be noted that all existing RAS have gone through regional reviews and been approved for implementation. These existing RAS may not have met the existing single component failure requirement due to the revision of the BES. The regions each have a process for ensuring the reliability of the BES and the necessary level of reliability and security has been met at the time of approval. Furthermore, misoperations studies have not indicated that there is a reliability need to incorporate single component failure design into local systems. These local RAS, which do not meet the requirement, would need to be redesigned, undergo outages, and then have revisions made to bring them into compliance. This, in and of itself would represent a risk to the operation and reliability of the BES.

Requirement R4 Part 4.4 currently states:

"4.4 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 is designed."

We suggest Part 4.4 be removed. However, if the SDT is unwilling to remove it, we propose the following:

"4.4 A single component failure in the RAS, when the RAS is intended to operate, does not result in any of the following conditions on the BES:

- Cascading
- Uncontrolled System Separation
- Instability"

The above modification would provide the necessary level of security and reliability to the BES. This ensures that RAS installed on the BES or installed to meet TPL requirements would only be required to meet Part 4.4 when the RAS operation is critical and any inadvertent operation results in a significant impact to the BES.

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

Document Name:

Likes:	0
Dislikes:	0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter	Segment
Pamela Hunter	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Kiguel - David Kiguel - 8 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Information

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter	Segment
Charles Yeung	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	

Selected Answer: Yes

Answer Comment:

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

See comment in no. 7.

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment:

Requirement R4 Part 4.4 is problematic for a number of reasons. First, placing this requirement on the Transmission Planner does not conform to the responsibilities or abilities of the Transmission Planner. The TP, although may have some familiarity with the design of the RAS or with the Operating Procedures which may be in place does not know or need to know the specifics of a single component failure, just the ramification of an overall RAS operation failure or inadvertent operation. Currently, the unapproved standard PRC-012-0 and -1 R1.3 contains a single component failure design requirement which is currently unapproved by FERC and the applicable governmental authorities in Canada. When these standards were approved there was no NERC BES definition nor was there an approved definition of what a RAS is. We believe that had the full implication of the costs to be borne by the industry been recognized and subsequent minimal or no reliability benefit associated with meeting that requirement for local impact only schemes, the standard would not have been approved. Further, the System Protection Coordination Subcommittee of NERC had specifically noted and suggested that 4 types of RAS are on the BES. Two of these were local and these categories were developed to afford the SDT to tailor specific and appropriate reliability and security requirements on these local type schemes. To broadly apply these more stringent requirements to all RAS on the new BES with the new RAS definition has no cost benefit. In addition, the existing PRC-012-0 and -1 only require a single component failure review and design requirement at the time of review. PRC-014-0 and -1, which are the SPS/RAS assessment standards currently do not require the Transmission Planner to include a requirement such as Requirement R4 Part 4.4 in their

	periodic assessment. The SDT has gone, in our view, unnecessarily beyond the intent of the current standards in this regard. In addition it should be noted that all existing RAS have gone through regional reviews and been approved for implementation. These existing RAS may not have met the existing single component failure requirement due to the revision of the BES. The regions each have a process for ensuring the reliability of the BES and that the necessary level of reliability and security had been met at the time of approval. Furthermore, misoperations studies have not indicated that there is a reliability need to incorporate single component failure design into local systems. These local RAS which do not meet the requirement would need to be redesigned, outages taken and then have their revisions made to come into compliance. This, in and of itself would represent a risk to the operation and reliability of the BES. Requirement R4 Part 4.4 currently states; "4.4 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 is designed." We suggest Part 4.4 be removed. However, if the SDT is unwilling to remove it we would propose the following: 4.4 A single component failure in the RAS, when the RAS is intended to operate, does not result in any of the following conditions on the BES: o Cascading o Uncontrolled System Separation o Instability The above modification would provide the necessary level of security and reliability to the BES. Ensuring that RAS installed on the BES or to meet TPL requirements would only be required when the RAS operation is critical and any inadvertent operation results in a significant impact to the BES. Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.
Document Name:	
Likes:	0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter	Segment
Randi Heise	5

Entity	Region(s)
Dominion - Dominion Resources, Inc.	

Selected Answer: No

Answer Comment:

Dominion believes that redundancy should not be required for a RAS designed for events such as TPL-001-4 P4 (stuck breaker) or P5 (relay failure event). The design should not have to consider two failures which is improbable. As an analogy, in places where there is no RAS scheme, there is no requirement to test a P4 stuck breaker event and then assume that the breaker failure relay does not work, essentially combining P4 and P5 together. Designing a redundant RAS for breaker failure could require installation of two breaker failure relays per breaker to initiate the RAS and maintain complete redundancy. This leads to excessive complexity which can hurt reliability.

Additionally, Dominion suggest adding clarity to indicate the intent of R4 is not to evaluate the performance of the RAS “following” an inadvertent operation since this is covered by R5. The rationale statement for R4 can be misinterpreted to imply R4 requires the Transmission Planner to perform a technical evaluation **“following”** an inadvertent operation.

	Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.
Document Name:	
Likes:	0
Dislikes:	0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter	Segment
John Seelke	1,3,5,6
Entity	**Region(s)**
PSEG	NPCC,RFC

Selected Answer:

Answer Comment:

No comment

Document Name:

Likes: 4

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Voter Information

Voter	Segment
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer: No

Answer Comment:

Requirement R4 Part 4.4 is problematic for a number of reasons. First, placing this requirement on the Transmission Planner does not conform to the responsibilities or abilities of the Transmission Planner. The TP may have some familiarity with the design of the RAS or with the Operating Procedures which may be in place, but does not know or need to know the specifics of a single component failure, just the ramification of an overall RAS operation failure or inadvertent operation. Currently, Part R1.3 of standards PRC-012-0 and -1 contains a single component failure design requirement. When these standards were approved by the NERC BOT there was no NERC BES definition nor was there an approved definition of what a RAS is. We believe that had the full implication of the costs to be borne by the industry been recognized and subsequent minimal or no reliability benefit associated with meeting that requirement for local impact only schemes, the standard would not have been approved by the NERC BOT. Furthermore, the System Protection Coordination Subcommittee of NERC had specifically noted and suggested that 4 types of RAS are on the BES. Two of these were local and these categories were developed to afford the SDT to tailor specific and appropriate reliability and security requirements on these local type schemes. To broadly apply these more stringent requirements to all RAS on the new BES with the new RAS definition has little cost benefit. In addition, the existing PRC-012-0 and -1 only require a single component failure review and design requirement at the time of review. PRC-014-0 and -1, which are the SPS/RAS assessment standards currently do not require the Transmission Planner to include a requirement such as Requirement R4 Part 4.4 in their periodic assessment. The SDT has gone unnecessarily beyond the intent of the current standards in this regard.

In addition it should be noted that all existing RAS have gone through regional reviews and been approved for implementation. These existing RAS may not have met the existing single component failure requirement due to the revision of the BES. The regions each have a process for ensuring the reliability of the BES, and that the necessary level of reliability and security had been met at the time of approval. Furthermore, misoperation studies have not indicated that there is a reliability need to incorporate single component failure design into local systems. These local RAS which do not meet the requirement would need to be redesigned, outages taken, and then revisions made to come into compliance. This, in and of itself would represent a risk to the operation and reliability of the BES.

Requirement R4 Part 4.4 currently states;

“4.4 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 is designed.”

We suggest Part 4.4 be removed. However, if not removed, we propose the following:

4.4 A single component failure in the RAS, when the RAS is intended to operate, does not result in any of the following conditions on the BES:

- Cascading
- Uncontrolled System Separation
- Instability

The above modification would provide the necessary level of security and reliability to the BES. Ensuring that RAS installed on the BES or installed to meet TPL requirements would only be required when the RAS operation is critical, and any inadvertent operation results in a significant impact to the BES.

Document Name:

Likes: 0

Dislikes: 0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

ERCOT supports the comments submitted by the ISO/RTO Council.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: No

Answer Comment:

Single component failures should exclude station dc supply and some portions of communications systems (e.g., microwave towers and multiplexing equipment). Such exceptions have existed in the industry.

For a single component failure, it is unclear why the requirement was changed from simply having to meet the performance requirements defined in TPL standards to having to meet those required for the events and conditions for which the RAS is designed.

In the Q & A document, section 5, page 4, how can arming excess load and generation not impact reliability? TPL footnote 9 notes that “the planning process should be to minimize the likelihood and magnitude of interruption.” RAS entities should be allowed to consider whether a 100% chance of tripping too much load/generation in the event of correct RAS operation really meets the intent of TPL. In some cases, allowing a single point failure to degrade the performance of the RAS is a better overall choice for minimizing total probability of interruption.

In the Q & A document, section 5, page 4, what kind of automatic actions are referenced? As the NERC reliability standards have evolved, the classification of RAS has expanded from just very high complexity protection schemes to now include many kinds of routine automatic actions. Almost any automatic action used to mitigate a TPL violation would become a RAS by virtue that it is used to meet requirements identified in a NERC Reliability Standard.

Document Name:

Likes: 0

Dislikes: 0

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

At the present time there are RAS in service that have a limited local impact. To universally apply the same design criteria to all RAS regardless of their impact on BES in case of failure to operate may have no cost benefit in the case of the RAS installed to address local problems.

We propose the following to be included in the standard:

The failure of a RAS to operate does not result in any of the following conditions on the BES:

1. Cascading
2. Uncontrolled System Separation
3. Instability

When the criteria mentioned above is not met a redundant design will be required.

When a RAS is used to respond to an event, e.g. category P1 in TPL-001-4, its failure should be considered to be a more severe event, just as in TPL-001-4 the failure of a breaker or protection relay following a P1 event is recognized as “Multiple Contingency” (category P3 and P4). For this reason, the system performance with a RAS failure should not be required to meet the same requirements (defined in TPL-001-4) as those for the original event.

We suggest that the system performance requirement in case of failure of a single component of a RAS be limited to the following:

1. The BES shall remain stable
2. Cascading or Uncontrolled System Separation shall not occur

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer: Yes

Answer Comment:

The California ISO supports the comments of the ISO/RTO Standards Review Committee

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Gallo - Austin Energy - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dixie Wells - Lower Colorado River Authority - 5 -

Group Information

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Voter Information

Voter	**Segment**
Dixie Wells	5
Entity	**Region(s)**
Lower Colorado River Authority	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

When a RAS is used to respond to an event, e.g. category P1 in TPL-001-4, its failure should be considered to be a more severe event, just as in TPL-001-4 the failure of a breaker or protection relay following a P1 event is recognized as "Multiple Contingency" (category P3 and P4). For this reason, the system performance with a RAS failure should not be required to meet the same requirements (defined in TPL-001-4) as those for the original event.

We suggest that the system performance requirement in case of failure of a single component of a RAS be limited to the following:

1. The BES shall remain stable

2. Cascading or Uncontrolled System Separation shall not occur

Please also see the following comments for relaxing the requirements for a class of RAS.

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter	Segment
Carol Chinn	4
Entity	**Region(s)**
Florida Municipal Power Agency	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Voter Information

Voter

Brian Van Gheem

Segment

6

Entity

ACES Power Marketing

Region(s)

NA - Not Applicable

Selected Answer: No

Answer Comment:

We recommend that the SDT consolidate the numerous sub-parts in Requirement R4, as they are confusing to both registered entity and auditor.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

5. Corrective Action Plans: Do you agree that the application of Requirements R6 and R7 would address the reliability objectives associated with CAPs? If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer: No

Answer Comment:

We suggest that the RAS-owner be removed from the Requirements, and that only the RAS-entity be subject to these Requirements. See below for more comments.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:

AEP believes R6 should be further revised to clarify exactly when the “six calendar months” begins. We suggest revising it to state ”Within six-full-calendar months of *the RC* being notified of a deficiency…”

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer: No

Answer Comment:

The NSRF recommends revising R6 to explicitly include the Planning Coordinator with working like, “. . . submit the CAP to its reviewing Reliability Coordinator and impacted Transmission Planners and Planning Coordinators”. The inclusion of Transmission Planners and Planning Coordinators is appropriate because these entities will generally have the best planning horizon information and expertise to review the CAP.

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

There appears to be a gap between R6 and R7, from the point where each RAS owner submits a CAP to its RC, and then implementing the CAP. There should be a requirement placed upon the RC where a review of the CAP is completed and feedback provided to the RAS owner.

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter

Ginette Lacasse

Segment

1,3,4,5,6

Entity

Seattle City Light

Region(s)

WECC

Selected Answer: No

Answer Comment:

The requirement R7 is very ambiguous about the time-frame for implementing a corrective action plan. Who approves the proposed schedule?

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Group Information

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Voter Information

Voter	Segment
Chris Scanlon	1
Entity	**Region(s)**
Exelon	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: No

Answer Comment:

R6 and R7 should specify a CAP is created only if deficiency is on the RAS-owners part of the RAS. As written, all RAS-owners would be responsible for submitting CAPs if a single deficiency was identified on just one part of the RAS. As written, a RAS-owner would be responsible for writing a CAP and implementing the CAP for something they may have no control over, if the deficiency is on another RAS-owners part of the RAS.

Document Name:

Likes: 0

Dislikes: 0

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Although the Corrective Action Plan (CAP) does address the reliability objectives it is unclear on the responsibilities of the parties involved. As the requirement is written, the Owner must submit the corrective action plan. There is a little confusion on any RAS that have multiple owners. Would ALL the owners need to submit a CAP or only the owner of the equipment in question? SRP recomends clarifying and possibly designating operator as the one to submit the CAP.

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment:

Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Document Name:

Likes: 0

Dislikes: 0

David Greene - SERC - 1,10 - SERC

Group Information

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Voter Information

Voter	Segment
David Greene	1,10
Entity	**Region(s)**
SERC	SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment:

ATC recommends revising R6 to explicitly include the Planning Coordinator with working like, ". . . submit the CAP to its reviewing Reliability Coordinator and any applicable Planning Coordinators". The inclusion of Planning Coordinators is appropriate because Planning Coordinators will generally have the best information and expertise to review the CAP.

Document Name:

Likes: 0

Dislikes: 0

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: No

Answer Comment:

Requirement R6 reads as follows:

"Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS- owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)."

As written, R6 doesn't clearly assign the responsibility to the RAS-owner and only states they shall participate. Standard requirements need to be specific on who is responsible for what, and when. We also suggest that any CAP being submitted to the PC (we feel that the PC is appropriate as discussed in comments on R1) be a "mutually agreed upon" CAP. To address this issue we suggest the following:

Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to

Requirement R4 or Requirement R5, each RAS- owner shall develop a mutually agreed upon

Corrective Action Plan (CAP) with all affected Reliability Coordinators and submit the CAP to its reviewing Planning Coordinator(s).

We suggest that the full responsibility of the development of the CAP rest with the RAS-entity. The rationale box states this but it needs to be clear in the requirement. Irrespective of complexity, the need to collaborate with others and hire consulting services, the responsibility should rest solely on the RAS-owner.

Also there may be a need for an additional requirement to notify the PC and TOP when the CAP has been completed, and the RAS is performing correctly. We will leave this for consideration by the SDT and believe this brings specific closure to any RAS deficiency.

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: No

Answer Comment:

As mentioned in our previous comments, Peak recognizes that the RC or TOP may impose operating restrictions to ensure reliability until the RAS deficiency is resolved but maintains that the CAP should be reviewed by an independent party to assure that it addresses the reliability issues in a reasonable timeframe. . For example, a CAP could be created with an unreasonable timeframe that unnecessarily extends a reliability issue. This independent review by the RC and subsequent required action by the RAS-entity exists for new RAS but not for CAPs, which appears inconsistent with the intent of the Standard. A process similar to that described in R2 and R3 should also apply to CAPs and not just new and functionally modified RAS.

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We suggest the following rewording:

“Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS- owner shall develope a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s).”

R6 should reflect that it is either solely the RAS owner’s responsibility **or** both the RC and RAS owner must have responsibility and “participate” in developing the CAP together. If the CAP requires mutual participation to develop, then both parties (the RAS owner AND the RC) must have compliance responsibility.

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter	Segment
Pamela Hunter	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: No

Answer Comment:

Reclamation suggests that the RAS-entity should be responsible for the Corrective Action Plans (CAPs) called for in requirements R6 and R7. Each RAS-owner should not be responsible for developing CAPs and coordinating them with the Reliability Coordinator (RC) because this could result in duplication of efforts or inconsistent corrective actions. As outlined in the Technical Justifications, “[t]he purpose of the RAS-entity is to be the single information conduit with each reviewing Reliability Coordinator (RC) for all RAS-owners for each RAS.” When there are several owners involved in a RAS, the RC should communicate with the RAS-entity as one point of contact to ensure that an overall CAP addresses any RAS deficiencies.

Document Name:

Likes: 0

Dislikes: 0

David Kiguel - David Kiguel - 8 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Information

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter	Segment
Charles Yeung	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	

Selected Answer: No

Answer Comment:

The SRC agrees that the RAS entity should develop Corrective Action Plans to evaluate RASs to address issues and/or deficiencies identified by their evaluations, but would suggest that such entities be required to provide the Corrective Action Plans to their Reliability Coordinator ***and Planning Coordinator*** for review.

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

See comment in no. 7.

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment:

“Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS- owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s).”

As written, R6 doesn’t clearly assign the responsibility to the RAS-owner and only states they shall participate. Standard requirements need to be specific on who is responsible for what, and when. We also suggest that any CAP being submitted to the RC be a “mutually agreed upon” CAP. To address this issue we suggest the following:

Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS- owner shall develop a mutually agreed upon Corrective Action Plan (CAP) with all affected Reliability Coordinators and submit the CAP to its reviewing Reliability Coordinator(s).

We suggest that the full responsibility of the development of the CAP rest with the RAS-owner. The rationale box states this but it needs to be clear in the requirement. Irrespective of complexity, the need to collaborate with others and hire consulting services, the responsibility should rest solely on the RAS-owner.

Document Name:

Likes:	0
Dislikes:	0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter	Segment
Randi Heise	5
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer: Yes

Answer Comment:

Attachment 1, Section III-Implementation states, “5. Documentation describing the functional testing process.” Dominion recommends deleting this bullet. This information is not necessarily available during the preliminary design phase. The approval of the design is sought prior to detailed engineering. (Planning)

In R5 it states that the RAS owner analyzes the event, but in flow chart it states RAS owner and TP. Dominion suggests that the content in the Flow Chart be consistent with language of the Requirement.

R5 references the timeframe “within 120 calendar days”, however in other areas of the document the time frame is stated to be “within XX calendar months”. Dominion suggests updating the document to reflect the actual timeframe. Dominion also believes clarification is needed to establish “full calendar months” versus “months”.

Document Name:

Likes:	0
Dislikes:	0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter	Segment
John Seelke	1,3,5,6
Entity	**Region(s)**
PSEG	NPCC,RFC

Selected Answer: No

Answer Comment:

See the comments in #2, which is critical to R6. Furthermore, the team should modify the R6 phrase as shown below:

"…each RAS-owner shall participate in developing a Corrective Action Plan with the RAS-entity which shall and submit the CAP to its reviewing Reliability Coordinator…."

This will result in one RAS-entity submitted CAP to the reviewing RC.

Document Name:

Likes: 4 PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Voter Information

Voter

Lee Pedowicz

Segment

10

Entity

Northeast Power Coordinating Council

Region(s)

NPCC

Selected Answer: No

Answer Comment:

Requirement R6 reads as follows:

"Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS- owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)."

As written, R6 doesn't clearly assign the responsibility to the RAS-owner and only states they shall participate. Standard requirements need to be specific on who is responsible for what, and when. We also suggest that any CAP being submitted to the RC be a "mutually agreed upon" CAP. To address this issue we suggest the following:

Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS- owner and affected

	Reliability Coordinator(s) shall develop a mutually agreed upon Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s). Also, there may be a need for an additional requirement to notify the RC and TOP when the CAP has been completed, and the RAS is performing correctly. This should be considered by the SDT. This brings specific closure to any RAS deficiency. Requirement R5 stipulates that the RAS-owner identifies deficiencies to its reviewing RC. Suggest R6 be revised to read: “Within six-full-calendar months of identifying or of being notified of a…”
Document Name:	
Likes:	0
Dislikes:	0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Answer Comment:

ERCOT supports the comments submitted by the ISO/RTO Council.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer: No

Answer Comment:

TANC has concerns with the current language in R5, R6, and R7, because it appears these requirements would assign the same or similar responsibilities to "each RAS-owner" when a single RAS operates or fails to operate as expected. In circumstances where a single RAS has multiple RAS-owners, the current language would potentially create overlapping responsibilities to analyze the RAS performance and develop/implement a Corrective Action Plan. It seems that these responsibilities established in R5, R6, and R7 would be more appropriately assigned to the single RAS-entity for a RAS rather than to each RAS-owner.

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

Requirement R6 reads as follows:

"Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to

Requirement R4 or Requirement R5, each RAS- owner shall participate in developing a

Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability

Coordinator(s)."

As written, R6 doesn't clearly assign the responsibility to the RAS-owner and only states they shall participate. Standard requirements need to be specific on who is responsible for what, and when. We also suggest that any CAP being submitted to the RC be a "mutually agreed upon" CAP. To address this issue we suggest the following:

Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to

Requirement R4 or Requirement R5, each RAS- owner shall develop a mutually agreed upon

Corrective Action Plan (CAP) with all affected Reliability Coordinators and submit the CAP to its reviewing Reliability Coordinator(s).

We suggest that the full responsibility of the development of the CAP rest with the RAS-owner. The rationale box states this but it needs to be clear in the requirement. Irrespective of complexity, the need to collaborate with others and hire consulting services, the responsibility should rest solely on the RAS-owner.

Requirement R6 states, "Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5…", however, a notification does not come out of R5 since the applicability to both R5 and R6 is with the RAS owner.

Document Name:	
Likes:	0
Dislikes:	0

Richard Vine - California ISO - 2 -

Selected Answer: No

Answer Comment:

The California ISO supports the comments of the ISO/RTO Standards Review Committee

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Gallo - Austin Energy - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dixie Wells - Lower Colorado River Authority - 5 -

Group Information

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Voter Information

Voter

Dixie Wells

Segment

5

Entity

Lower Colorado River Authority

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE is concerned there could be an extended time frame where a RAS with a known deficiency will be in service since the requirement to develop a Corrective Action Plan (CAP) is do so within six months. Texas RE is also concerned there is no defined time frame for implementing the CAP.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The RC needs to be given the authority to reject the CAP, or suggest changes to the CAP.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

Hydro One Networks Inc. believes that as quoted below, R6 does not clearly assign the responsibility to the RAS-owner and only states that they “shall participate”.

“Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS- owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s).”

Standard requirements need to be specific on as to who is responsible for what, and when. We also suggest that any CAP being submitted to the RC be a “mutually agreed upon” CAP. To address these issues, we suggest revising the wording to read the following:

“Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to Requirements R4 and R5 state that each RAS- owner shall develop with all affected RCs, a mutually agreed upon Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)”. However, Hydro One Networks Inc. suggests that the full responsibility of the development of the CAP rest with the RAS-owner. The rationale box states that the full responsibility of the development of the CAP rests with the RAS-owner, but this needs to be clear, and explicitly stated in the requirement as well. Irrespective of complexity, the need to collaborate with others, hire consulting services, etc., the responsibility should rest solely on the RAS-owner.

Requirement R6 states, “Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5…”, however, Hydro One would like to point out that a notification does not result from requirement R5 since the applicability to both R5 and R6 is with the RAS owner themselves.

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter	Segment
Carol Chinn	4
Entity	**Region(s)**
Florida Municipal Power Agency	

Selected Answer: No

Answer Comment:

The RAS-entity should be included in Requirements R6 and R7 in a coordinating role between the RAS-owners and the TP and/or RC. It should be made clear that the RAS-owners are only responsible for their portion of the RAS.

Document Name:

Likes:	0
Dislikes:	0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Voter Information

Voter	Segment
Brian Van Gheem	6
Entity	**Region(s)**
ACES Power Marketing	NA - Not Applicable

Selected Answer: No

Answer Comment:

We disagree with the SDT that there needs to be two requirements to cover CAPs. These requirements should be consolidated and simplified to avoid unnecessary confusion and potential compliance impacts. Furthermore, CAPs are administrative in nature and we recommend removing these requirements under Paragraph 81 Administrative criteria.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

6. Implementation Plan: Do you agree with the Implementation Plan? If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer: Yes

Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter

Ginette Lacasse

Segment

1,3,4,5,6

Entity

Seattle City Light

Region(s)

WECC

Selected Answer: No

Answer Comment:

The requirement R7 is very ambiguous about the time-frame for implementing a corrective action plan. Who approves the proposed schedule?

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Group Information

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Voter Information

Voter	Segment
Chris Scanlon	1
Entity	**Region(s)**
Exelon	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment:

SRP notices possible confusion on the implementation for R4 and R8. The rationale for R4 and R8 state that the 60 month time period begins on the effective date of the standard. However, the implementation plan does not state that similarly. There is potential confusion for this as many entities are likely to attempt to have their evaluations and functional tests completed by the effective date.

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment:

Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Document Name:

Likes: 0

Dislikes: 0

David Greene - SERC - 1,10 - SERC

Group Information

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Voter Information

Voter	Segment
David Greene	1,10
Entity	**Region(s)**
SERC	SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

Peak interprets the Implementation Plan as grandfathering in all existing RAS, which means review and approval of existing RAS is not required – only for new or modified RAS. The revised Standard does not address existing RAS, and therefore neglects any potential reliability issues associated with them. Peak seeks clarity on this issue.

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter	Segment
Pamela Hunter	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Kiguel - David Kiguel - 8 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Information

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter	Segment
Charles Yeung	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

See comment in no. 7.

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment:

The Implementation Plan should be modified to include clarification for implementation of R4. TFSP suggests adding the language used in the Rationale box for R4, which says: "Sixty- full- calendar months, which begins on the effective date of the standard pursuant to the implementation plan…"

The standard or the Implementation Plan should allow the RAS-owner sufficient time to mitigate a design deficiency identified as part of R4, such as the lack of redundancy without removing the RAS from service. Clarification should be provided to allow for continued operation of an existing RAS after a single component failure scenario is identified until a Corrective Action Plan can be completed.

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter Randi Heise

Segment 5

Entity Dominion - Dominion Resources, Inc.

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter	Segment
John Seelke	1,3,5,6
Entity	**Region(s)**
PSEG	NPCC,RFC

Selected Answer: No

Answer Comment:

The effective date in Implementation Plan should be increased from 12 month to 36 months after the first day of the first calendar quarter after the date the standard is approved. This reason for this delay is that standard establishes a new working framework between RAS-owners, RAS-entities, TPs, and RCs. That itself will involve considerable start-up effort. In return for this added delay, the first periodic review of each RAS under R4 could be due within 36 months, with subsequent reviews every 60 months.

Document Name:

Likes: 4 PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Voter Information

Voter	Segment
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer: No

Answer Comment:

The Implementation Plan should be modified to include clarification for implementation of R4. Suggest adding the language used in the Rationale for Requirement R4, which says: "Sixty- full- calendar months, which begins on the effective date of the standard pursuant to the implementation plan…"

The standard or the Implementation Plan should allow the RAS-owner sufficient time to mitigate a design deficiency identified as part of R4, such as the lack of redundancy without removing the RAS from service. Clarification should be provided to allow for continued operation of an existing RAS after a single component failure scenario is identified until a Corrective Action Plan can be completed.

The Implementation Plan should address the possible scenario of a RAS misoperation occurring within 120 days of the Standard's effective date, and if R5

	would apply. Would this misoperation require the development of a CAP after the effective date of the Standard? This would apply for R6 and R7 as well. For testing records will the RAS-owner need to have documentation of testing prior to the standard's effective date? This should be clarified in the Implementation Plan.
Document Name:	
Likes:	0
Dislikes:	0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment:

N/A

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: No

Answer Comment:

In the Implementation Plan, page 2, the following sentence has a grammatical/mechanical issue: “As of the date of posting of this Implementation Plan, however, the Commission has not issued an Final Order approving and retirement the Reliability Standards enumerated above.”

Document Name:

Likes: 0

Dislikes: 0

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

The Implementation Plan should allow the RAS-owner sufficient time to mitigate a design deficiency identified as part of R4, such as the lack of redundancy without removing the RAS from service. Clarification should be provided to allow for continued operation of those RAS, that are already in service when the standard becomes effective, after a single component failure scenario is identified until a Corrective Action Plan can be completed.

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Gallo - Austin Energy - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dixie Wells - Lower Colorado River Authority - 5 -

Group Information

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Voter Information

Voter	Segment
Dixie Wells	5
Entity	**Region(s)**
Lower Colorado River Authority	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

The Implementation Plan should be modified to include clarification for implementation of R4. Hydro One Networks Inc. agrees with the NPCC's TFSP in adding the language used in the Rationale box for R4, which says: "Sixty- full-calendar months, which begins on the effective date of the standard pursuant to the implementation plan…"

The standard or the Implementation Plan should allow the RAS-owner sufficient time to mitigate a design deficiency identified as part of R4, such as the lack of redundancy without removing the RAS from service. Clarification should be

	provided to allow for continued operation of an existing RAS after a single component failure scenario is identified until a Corrective Action Plan can be completed.
Document Name:	
Likes:	0
Dislikes:	0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter	Segment
Carol Chinn	4
Entity	**Region(s)**
Florida Municipal Power Agency	

Selected Answer: Yes

Answer Comment:

The Implementation Plan should specify when the first 5 year evaluation required by R4 should be completed for an existing RAS.

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Voter Information

Voter	Segment
Brian Van Gheem	6
Entity	**Region(s)**
ACES Power Marketing	NA - Not Applicable

Selected Answer: No

Answer Comment:

We ask the SDT to clarify whether the approval process and the first technical evaluation needs to be performed before or after the effective date of the standard.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

7. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer:

Answer Comment:

We suggest that the standard have applicability to only the RAS entity, normally the primary Transmission Owner for the region affected. Including more than one party will make this standard too cumbersome and difficult to manage. The primary application of a RAS is to multi-facility, wide-area disturbances and as such is best vested in the Transmission Owner, who has a wider “system” viewpoint than the Generator Owner. We are concerned that Generator Owners may become inadvertent RAS-owners simply by owning a small fraction of the equipment needed for the RAS, and thus become subject to requirements R5 through R8, when they are typically passive parties to the RAS.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment: na

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

na

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer:

Answer Comment:	For R5, we propose revised wording that “within 120 days, or on a mutually agree upon schedule.” This would allow earlier or later completion of the analysis when warranted by unusual circumstances.
Document Name:	
Likes:	0
Dislikes:	0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:

Answer Comment:

With regards to R5:

What is the benefit of providing the reviewing RC with results of a successful RAS operation?

With regards to R8:

Although functional testing would verify that the scheme is working as designed, there is no reason to believe that an RAS is any different from another protection system i.e., it would need to be tested at intervals outside the normal maintenance program. The testing of RAS should fall in line with PRC-005-3 requirements for monitored systems and unmonitored systems.

By requiring “at least once every six calendar years, each RAS- owner shall perform a functional test,” the drafting team is forcing all owners of a RAS that has any Protection Systems in it to abandon the PRC-005-3 12 year Maximum Maintenance Intervals allowed in tables 1-1, 1-2, 1-3, 1-5, and 4.

If Requirement R9 is adopted as stated in this draft of the standard, each segment of a RAS would have to be tested at a maximum interval of 6 calendar years. This would require, for example, that voltage and current sensing devices providing inputs to protective relays of a RAS “shall” be tested “at least once every six calendar years” instead of 12 Calendar years allowed in Table 1-3 of PRC-005-3.

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter	Segment
Ginette Lacasse	1,3,4,5,6
Entity	**Region(s)**
Seattle City Light	WECC

Selected Answer:

Answer Comment:

1. We ask for a clarification on the PRC-012-2 definition of RAS Owner to only “exclusively” include the owner of the scheme, and not include a “participating” entity in the RAS operation. The participating entity equipment would be covered by other standards such PRC-005-2 and thus should be excluded from standard.

2. The requirement R8 will require that the RAS is tested every 6 years, which is equivalent to any unmonitored relays that we have under PRC-005. However, testing the RAS may prove to be more laborious since it will most likely require coordination among multiple participating entities, so a more relaxed test sequence (12 years) would be preferred.

Document Name:

Likes:	0
Dislikes:	0

Chris Scanlon - Exelon - 1 -

Group Information

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Voter Information

Voter

Chris Scanlon

Segment

1

Entity

Exelon

Region(s)

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer:

Answer Comment:

RAS-entity should be responsible for R5 instead of RAS-owner. The RAS-entity, being designated to represent all RAS-owners, is in the best position to evaluate the operation of a RAS.

RAS-entity should be responsible for R8 functional testing.

R9 should include a sub-requirement for RCs to share their database with neighboring RCs to provide coordination of RAS schemes near RC borders.

Document Name:

Likes: 0

Dislikes: 0

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer:

Answer Comment:

There are numerous references to components of a RAS scheme in the standard and supplemental material, but there is no clear definition of what constitutes a component of a RAS scheme. A lack of a clear definition can lead to different interpretations of what a RAS component is. For example, Requirement R4.3 requires that "the possible inadvertent operation of the RAS resulting from any single RAS component malfunctions satisfies all of the following" conditions in 4.3.1 thru 4.3.5. While it is implied that the RAS components could include elements such as the RAS controller, communications, control circuitry, supervisory relays or functions (breaker 52A contact), and/or voltage or current sensing devices, it is not clearly stated. This leaves it open for some entities to possibly consider additional items such as a circuit breaker as a RAS component and other entities to not consider it. It could also allow some entities to take a more relaxed approach and exclude components that should possibly be included. A definition or explanation of RAS components should be added to the standard similar to the definitions used in PRC-005-4 (i.e. Automatic Reclosing and Sudden Pressure Relaying).

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer:

Answer Comment:

Currently as the standard is written, R5 and R6 require each RAS-owner to submit the results of the analysis and a CAP if needed. Tri-State does not believe it should be required that each RAS-owner submit the results and/or CAP rather than the RAS-entity. The RAS-entity can collect the results and submit 1 report/CAP, instead of several individual submittals from the seperate RAS-owners.

Also, Tri-State believes there is a numbering issue in Section II of Attachment 1 of the standard. It looks like "Documentation showing that the possible inadvertent operation of the RAS resulting from any singles RAS component malfunction satisfies all of the following:" should be #5 since it is a separate topic from #4.

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

a. The Rationale Box for R6 states that the "RAS-owner" will need to submit information in Attachment 1 to the RC, should this be the RAS-entity?

b. In R6, if the RAS-owner is the entity that performed the analysis in R4 of R5, when does the 6 month clock start (i.e., when was it notified)?

c. For R7, is the intent that each RAS-owner update the CAP with the RC? It seems like this should be the job of the RAS-entity, not multiple RAS-owners.

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

As written the rationale for R8 is not incorporated into the requirement. R8 rationale states that correct operation of a RAS segment would qualify as a functional test. Please state that in the requirement so there is no confusion or debate if a correct operation resets the time frame necessary to perform a test.

SRP recommend the removal of the word “Requirement” in front of any R# designation. R1 stands for Requirement 1 and is sufficient. Saying "Requirement R1" is like saying Requirement Requirement 1. Also, the term “Requirement” is not a defined term.

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:

Answer Comment:

Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Document Name:

Likes: 0

Dislikes: 0

David Greene - SERC - 1,10 - SERC

Group Information

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Voter Information

Voter	Segment
David Greene	1,10
Entity	**Region(s)**
SERC	SERC

Selected Answer:

Answer Comment:

If a RAS has multiple owners, and one or more owners is not compliant to R8, does this mean that all owners, or the RAS-entity, are non-compliant?

Document Name:

Likes: 0

Dislikes: 0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer:

Answer Comment:

IMEA questions the need to include DP in the applicability. It is likely a DP will only own a part of a RAS. It should be adequate to specify TO coordination to verify RAS performance.

In R8, IMEA recommends deletion of "...and the proper operation of non-Protection System components."; i.e., it should be adequate to indicate only "...verify overall RAS performance."

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

- For R5, ATC proposes revising wording that "within 120 days, or on a mutually agree upon schedule." This would allow earlier or later completion of the analysis when warranted by unusual circumstances.
- The purpose of Version 2 of PRC-005 was to consolidate all maintenance and testing of relays under one Standard. Having RAS testing within PRC-012-2 would be contrary to that end. ATC addresses this concern as follows:

Functional testing of RAS (as stated in Requirement 8 of PRC-012-2) is a maintenance and testing activity that would be better included in the PRC-005 standard. The present PRC-005-2 Reliability Standard is the maintenance standard that replaces PRC-005-1, 008, 011 and 017 and was designed to cover the maintenance of SPSs/RASs. However, Reliability Standard PRC-005-2 lacks intervals and activities related to non-protective devices such as programmable logic controllers. ATC recommends that a requirement for maintenance and testing of non-protective RAS components be added to a revision of PRC-005-2, rather than be an outlying maintenance requirement located in the PRC-012-2 Standard.

Document Name:

Likes: 0

Dislikes: 0

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer:

Answer Comment:

Regarding the rationale for Requirement R8--We agree with segmented testing. However, the requirement does not state this and implies an overall test should still be performed.

R8 currently states:

At least once every six- calendar years, each RAS- owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components.

Suggest revising to:

At least once every six- calendar years, each RAS- owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. This test can be either:

o An end to end test encompassing all components and testing actual functionality

o A segmented test to test all the components by grouping them together into blocks until all parts of the RAS have been tested

Additional information in the Technical Guideline may be required to explain how the six year cycle is measured when allowing segmented testing. Segmented testing can test all components of an RAS every six years, but an individual component could end up being tested once every 10 years. For example, a RAS is designed so that it is comprised of a segment “A”, and a segment “B”. Segment “A” is tested in year 1, segment “B” is tested in year 5. As per Requirement R8 the RAS has been tested within “six-calendar years.” The clocks starts for the next functional test period, and segment “B” is tested in year 1 (one year since its first test), and segment “B” tested in year 5 (nine years since its first test). The RAS was tested within the “six-calendar years”, but segment “B” had a nine year interval. The requirement should be modified to state that all segments shall be tested in the same calendar year.

The RAS-owner should be included in Attachment 3.

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer:

Answer Comment:

Peak was unable to locate the “consideration of comments” after the last round of comments posted on the NERC website. The “consideration of comments” are normally posted as part of the Standards Drafting Process to help commenters understand the SDT approach to comments made, and can affect subsequent comments submitted. Peak encourages NERC to post a “consideration of comments” from all comment periods.

In Attachment 2 under I: Design bullet 6, it states that the effects of future BES modifications… this seems to go outside of the scope of the operating horizon on which the RC is focused.

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

In the Rationale for Requirement R1, the last sentence of the first paragraph is “A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality.” How will “any modification to a RAS beyond the replacement of components” preserve the original functionality? The term “functional modification” requires clarification. Suggest developing a formal definition:

RAS Functional Modification--a change to the resultant action for which a RAS is designed.

Rationale for Requirement R8--We agree with segmented testing. However, the requirement does not state this and implies an overall test should still be performed.

R8 currently states:

“At least once every six- calendar years, each RAS- owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components.”

Suggest revising to:

	"At least once every six- calendar years, each RAS- owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. This test can be either: • An end to end test encompassing all components and testing actual functionality • A segmented test to test all the components by grouping them together into blocks until all parts of the RAS have been tested" Additional information in the Technical Guideline may be required to explain how the six year cycle is measured when allowing segmented testing. Segmented testing can test all components of an RAS every six years, but an individual component could end up being tested once every 10 years. For example, a RAS is designed so that it is comprised of a segment "A" and a segment "B". Segment "A" is tested in year 1, segment "B" is tested in year 5. As per Requirement R8, the RAS has been tested within "six-calendar years." The clocks starts for the next functional test period and segment "B" is tested in year 1 (one year since its first test) and segment "A" tested in year 5 (nine years since its first test). The RAS was tested within the "six-calendar years", but segment "A" had a nine year interval. Is this what is intended? The RAS-owner should be included in Attachment 3.
Document Name:	
Likes:	0
Dislikes:	0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter	Segment
Pamela Hunter	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer:

Answer Comment:

1. Regarding R1, it is not clear what the term “Functionally Modified” means. “A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality” does not make sense. Does changing some overall scheme's functional logic without replacing any hardware device qualify as “Functional Modified”?

2. R2 should be changed to “Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1, shall, within four- full- calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback including any identified reliability issues to the RAS- entity”.

3. R3 should be changed to “Following the review performed pursuant to Requirement R2 and receiving the feedback from the reviewing RC, the RAS-entity shall address each identified issue and obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in service or retiring an existing RAS.

4. R5 requires RAS owner to analyze the performance of every RAS operations. It is not clear how much detail is required in this analysis. For those RAS schemes that operates routinely and regularly as designed, is a declaration of correct operation sufficient analysis?

5. R6 should be changed to “Within six- full- calendar months of identifying or being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS- owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)”.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

Reclamation suggests that the drafting team remove Generator Owners from the applicability section of the standard. Reclamation is unclear on how a Generator Owner could be considered to own all or part of a RAS. Reclamation does not believe that Generator Owners are well situated to analyze system-level RAS impacts or be considered a RAS-entity.

Reclamation believes that a list of elements that may constitute remedial action scheme elements would be helpful for understanding the scope of the standard. Project 2010-05.2, Phase 2 of Protection Systems, defines RAS by listing elements which do not individually constitute RAS. Reclamation is unclear on whether only protection system elements are intended to be considered part of a RAS, or whether elements affected by RAS operation like transmission lines or generators may also be considered RAS elements. Reclamation suggests the inclusion of a guidelines and technical basis section that better defines the parameters of RAS that must be analyzed under R4 and R6, and their relationship to system elements affected by RAS.

Reclamation also suggests that the RAS-entity should be responsible for the R5 analysis of each RAS operation or each failure of a RAS to operate. As written, the requirement would impose duplicative analysis requirements upon RAS owners that would not result in a corresponding reliability benefit. In addition, Reclamation believes that requiring each RAS-owner to conduct an analysis of each RAS operation is unwarranted because owners of one component of a RAS, such as a Generator Owner, would not be in the best position to analyze the RAS operation or its impact on the system. The RAS-entity is the RAS-owner designated to represent all RAS-owners for coordinating the review and approval of a RAS. As outlined in the Technical Justifications, “[t]he purpose of the RAS-entity is to be the single information conduit with each reviewing Reliability Coordinator (RC) for all RAS-owners for each RAS.” Reclamation believes the RAS analysis requirement should apply to the entity best situated to analyze the overall RAS operation, the RAS-entity.

Finally, Reclamation suggests that the RAS-entity should be responsible for the R8 functional test of each RAS that is required at least once every six calendar years. A RAS-owner responsible for limited RAS components would not be able to verify the overall RAS performance. The RAS-entity should be responsible for coordinating a functional test with all RAS-owners.

Document Name:	
Likes:	0
Dislikes:	0
David Kiguel - David Kiguel - 8 -	
Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0
Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -	
Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

1. Applicability Section:

    i. ReliabilityFirst believes the “RAS- entity” functional entity under the “Applicability” section may cause issues regarding which entity is responsible for requirements related to the “RAS- entity”. Absent any requirements requiring the RAS-owners to designate and make known the official RAS- entity, it may be difficult to assess compliance on the RAS-entity. ReliabilityFirst recommends including a new Requirement R1 as follows:

        a. R1. For each RAS that is owned by multiple RAS- owners, the RAS-owners shall designate one RAS- entity and inform the Reliability Coordinator(s) and Transmission Planner(s) that coordinates the area(s) where the RAS is located of such designation

2. Requirement R5

    i. As written, if there are multiple RAS-owners of a RAS, the expectation is to have multiple analyses performed. ReliabilityFirst believes it would be more appropriate to require the RAS-entity to perform one analysis with coordination of all associated RAS-owners.

3. Requirement R8

    i. Requirement R8 requires each RAS- owner to perform a functional test of each RAS. As written, in the case where multiple RAS-owners own a single RAS, multiple tests of the same RAS would be required to be run. ReliabilityFirst believes in cases where a RAS is owned by multiple RAS-owners, a single test should be required by the designated RAS-entity in conjunction with all the RAS-owners.

4. VSL for Requirement R4

    i. The time frames for the VSL for Requirement R4 are not all inclusive. For example, the Lower VSL states “less than 61- fullcalendar months” while the moderate VSL states “greater than 61- full- calendar months”. In this example it is unclear which VSL category an entity falls under if they perform the evaluation in 61 months. Listed below is an example of the Lower VSL for the SDT's consideration.

a. The Transmission Planner performed the evaluation in accordance with Requirement R4, but in greater than 60- full- calendar months but less than **[or equal to]** 61-fullcalendar months.

5. VSL for Requirement R7

i. The Lower VSL states that if an entity failed both 7.2 and 7.3 they would fall under the Lower category. ReliabilityFirst questions what VSL an entity would fall under in the scenario where an entity is compliant with 7.2 but not 7.3?

- The RAS- owner implemented a CAP (Part 7.1), but failed to update the CAP (Part 7.2) if actions or timetables changed **[OR]** failed to notify one or more of the reviewing Reliability Coordinator(s) (Part 7.3), in accordance with Requirement R7.

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Information

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter	Segment
Charles Yeung	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	

Selected Answer:

Answer Comment:

Requirement R5: The SRC agrees that the RAS entity should evaluate RASs under the circumstances identified in Requirement R5, but would suggest that such entities be required to provide the results of such assessments to their Reliability Coordinator ***and Planning Coordinator***.

Requirement R9: In conjunction with the comment provided under Q2 to replace the TP with the PC, while the SRC agrees that the RC is the appropriate entity to maintain the database, it suggests that the Reliability Coordinator be required to share its database with the applicable Planning Coordinator(s) as some entities may have a need for planned RAS information for modeling and to ensure that appropriate information is shared across the long- and short-term horizons.

Document Name:

Likes:	1	Electric Reliability Council of Texas, Inc., 2, Axson Elizabeth
Dislikes:	0	

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer:

Answer Comment:

Entergy supports the SERC PCS comments on this standard.

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Eversource Energy - 3 -

Selected Answer:

Answer Comment:

Regarding the Applicability Section 4.1.4 for the RAS-entity, who designates the RAS-owner to represent all RAS-owner(s)?

In the Rationale for Requirement R1, last sentence of the first paragraph, “A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality.” How will “any modification to a RAS beyond the replacement of components” preserve the original functionality? Functional modification requires clarification. Suggest developing a formal definition:

RAS Functional Modification--a change to the resultant action for which a RAS is designed.

Rationale for Requirement R8--We agree with segmented testing. However, the requirement does not state this and implies an overall test should still be performed.

R8 currently states:At least once every six- calendar years, each RAS- owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components.

Suggest revising to: At least once every six- calendar years, each RAS- owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. This test can be either:

o An end to end test encompassing all components and testing actual functionality

o A segmented test to test all the components by grouping them together into blocks until all parts of the RAS have been tested

Additional information in the Technical Guideline may be required to explain how the six year cycle is measured when allowing segmented testing. Segmented testing can test all components of an RAS every six years, but an individual component could end up being tested once every 10 years. For example, a RAS is designed so that it is comprised of a segment "A", and a segment "B". Segment "A" is tested in year 1, segment "B" is tested in year 5. As per Requirement R8 the RAS has been tested within "six-calendar years." The clocks starts for the next functional test period, and segment "B" is tested in year 1 (one year since its first test), and segment "B" tested in year 5 (nine years since its first test). The RAS was tested within the "six-calendar years", but segment "B" had a nine year interval. Is this what is intended?

The RAS-owner should be included in Attachment 3.

R8 and guidance provided in the supplemental material as written appears to overstep the direction provided by the SAR which states that the standard will address maintenance and testing on non-Protection System components of a RAS. Maintenance of Protection Systems installed as a RAS for BES reliability is clearly covered in PRC-005. NPCC is very concerned that there are different timeframes and duplicative testing for RAS components. In particular, the supplemental material provided is very confusing and appears to suggest duplicative testing compared to testing already required in PRC-005. NPCC suggests that all testing requirements for RAS should be contained in one standard.

NPCC suggests deletion of the phase "including any identified deficiencies" in R5 because requirements R5.1 through R5.4 clearly define the necessary level of analysis required by the RAS-owner. Leaving this phrase in will lead to confusion over whether the proper operation of a "composite" RAS is considered a deficiency if one of the two redundant RAS suffer a component failure.

Document Name:

Likes: 0

Dislikes:	0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter	Segment
Randi Heise	5
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer:

Answer Comment:

Attachment 1, Section III-Implementation states, “5. Documentation describing the functional testing process.” Dominion recommends deleting this bullet. This information is not necessarily available during the preliminary design phase. The approval of the design is sought prior to detailed engineering. (Planning)

In R5 it states that the RAS owner analyzes the event, but in flow chart it states RAS owner and TP. Dominion suggests that the content in the Flow Chart be consistent with language of the Requirement.

R5 references the timeframe “within 120 calendar days”, however in other areas of the document the time frame is stated to be “within XX calendar months”. Dominion suggests updating the document to reflect the actual timeframe. Dominion also believes consistency is needed and suggests the timeframes reflect "full calendar months” versus “months”.

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter	Segment
John Seelke	1,3,5,6
Entity	**Region(s)**
PSEG	NPCC,RFC

Selected Answer:

Answer Comment:

1. In addition to RAS-entity's, RAS-owners also have compliance obligations. Yet RAS-owners are not identified in any of the attachments. In addition, the RAS-related equipment of each owner should be identified in one attachment for use by the Reliability Coordinator, the Transmission Planner, and the Compliance Enforcement Authority. Expanding Attachment 3 may be the most efficient way to address these concerns.

2. R5 should be modified by changing this phrase: "…analyze the RAS performance…" to "analyze the performance of its RAS-related equipment." In cases where there are multiple RAS owners, a single RAS-owner cannot analyze the performance of the entire RAS; it can only analyze the performance of its own RAS-related equipment.

Document Name:

Likes:	4	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla PSEG - PSEG Fossil LLC, 5, Kucey Tim PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
Dislikes:	0	

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer:

Answer Comment:

FirstEnergy would like additional clarification on the phrase “RAS controller” in the second paragraph of the Supplemental Material section in “Applicability”, 4.1.4 RAS-entity.

Additionally, FirstEnergy seeks to confirm that if a RAS system operates as planned/designed durnng normal operations then can the data from this actual operation be used to verify/satisfy testing requirements?

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Voter Information

Voter	Segment
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer:

Answer Comment:

Because feeder loading can be changed intentionally, it is frequent to add, substitute, or remove load tripping devices (not distributed relays) in order to maintain the amount of load that is required by a load tripping RAS. Would these changes constitute a RAS functional modification? If so, suggest revising the definition of RAS functional modification. The Attachment 1 procedure that would have to be applied would be overly burdensome.

Regarding the Applicability Section 4.1.4 for the RAS-entity, who designates the RAS-owner to represent all RAS-owner(s)?

In the Rationale for Requirement R1, last sentence of the first paragraph, “A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality.” How will “any modification to a RAS beyond the replacement of components” preserve the original functionality? Functional modification requires clarification. Suggest developing a formal definition:

RAS Functional Modification--a change to the resultant action for which a RAS is designed.

Rationale for Requirement R8--We agree with segmented testing. However, the requirement does not state this and implies an overall test should still be performed.

R8 currently states:

At least once every six- calendar years, each RAS- owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components.

Suggest revising to:

At least once every six- calendar years, each RAS- owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. This test can be either:

- An end-to-end test encompassing all components and testing actual functionality

    - A segmented test to test all the components by grouping them together into blocks until all parts of the RAS have been tested

Additional information in the Technical Guideline may be required to explain how the six year cycle is measured when allowing segmented testing. Segmented testing can test all components of an RAS every six years, but an individual component could end up being tested once every 10 years. For example, a RAS is designed so that it is comprised of a segment “A”, and a segment “B”. Segment “A” is tested in year 1, segment “B” is tested in year 5. As per Requirement R8 the RAS has been tested within “six-calendar years.” The clock starts for the next functional test period, and segment “B” is tested in year 1 (one year since its first test), and segment “A” tested in year 5 (nine years since its first test). The RAS was tested within the “six-calendar years”, but segment “A” had a nine year interval. Is this what is intended? It should be required that all segments be tested in the same calendar year.

The RAS-owner should be included in Attachment 3.

Requirement R8 and guidance provided in the supplemental material as written go beyond the direction stipulated by the SAR which states that the standard will address maintenance and testing on non-Protection System components of a

RAS. Maintenance of Protection Systems installed as a RAS for BES reliability is clearly covered in PRC-005. We are very concerned that there are different timeframes and duplicative testing for RAS components. In particular, the supplemental material provided is very confusing and appears to suggest duplicative testing compared to testing already required by PRC-005. Suggest that all testing requirements for RAS should be contained in one standard. The testing time periods should be made consistent with Table 1-1 in PRC-005, specifically 6 years for an unmonitored protection system, and 12 years for an unmonitored microprocessor protection system.

NPCC suggests deletion of the phase “including any identified deficiencies” in R5 because Parts 5.1 through 5.4 clearly define the necessary level of analysis required by the RAS-owner. Leaving this phrase in will lead to confusion over whether the proper operation of a “composite” RAS is considered a deficiency if one of the two redundant RAS suffer a component failure.

In C. Compliance, Section 1.2 Evidence Retention: the RC and TP have not been included. The TO, GO and DP are requested to keep data for requirements that they might not be responsible for.

Document Name:

Likes: 0

Dislikes: 0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer:

Answer Comment:

Tacoma Power recommends that the definition of 'RAS-owner' be limited to functional ownership, as opposed to component ownership. For example, if one company owns a station DC supply, some wiring, and trip coil, but another company owns the control device at the same location, the entity that owns the control device should be a RAS-owner, and the entity that owns the station DC supply, wiring, and trip coil should not be a RAS-owner. Another example would be an entity that owns sensing devices that another entity uses to provide inputs to a relay or PLC that it owns; the entity that owns the sensing devices in this example should not be a RAS-owner. Yet another example is when one entity owns a portion of the communications system; simply owning part of the communications system should not make the entity a RAS-owner.

In the Q & A document, section 9, top of page 6, what if timing is only critical on the order of minutes (e.g., remediation of thermal overload). Could replacement of a T1 multiplexor possibly not be considered a RAS functional change in this case?

In the Q & A document, section 9, page 6, the example of “replacement of a failed RAS component with an identical component” seems overly exclusive. It is recommended to replace “identical” with “substantially identical.”

In Requirement R6, why is “six-full calendar months,” instead of simply “six calendar months,” used?

In the Supplemental Material section, page 27, the following sentence has a grammatical/mechanical issue: “A RAS is only allowed to drop non-consequential load or interrupt Firm Transmission Service can do that only if that action is allowed for the Contingency for which it is designed.”

In the Supplemental Material section, page 28, the following passage does not seem to read well: “These changes could result in inadvertent activation of that output, therefore, tripping too much load and result in violations of Facility Ratings. Alternatively, the RAS might be designed to trip more load than necessary (i.e., “over trip”) in order to satisfy single- component- failure requirements. System changes could result in too little load being tripped at affected locations and result in unacceptable BES performance if one of the loads failed to trip.” Should the middle sentence be removed? It seems incongruous with the other two sentences.

In the Supplemental Material section, page 29, would a CAP be required if equipment fails that is readily replaceable/repairable? Tacoma Power maintains that CAP’s should be required for issues that will require a longer time to address. In general, notification of RAS equipment failures is addressed by other standards.

In the Supplemental Material section, page 30, change “the , the” to “then, the.”

Document Name:

Likes: 0

Dislikes: 0

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer:

Answer Comment:

Although neither the Applicability section nor the Requirements of this draft standard distinguish between Protection System components and non-Protection System components of a RAS, the associated supporting information does make such a distinction. For example, the first paragraph of the Background Information section on the Unofficial Comment Form includes the following:

"The maintenance of the Protection System components associated with RAS (PRC-017-1 Remedial Action Scheme Maintenance and Testing) are already addressed in PRC-005. PRC-012-2 addresses the testing of the non-Protection System components associated with RAS/SPS."

NERC's supporting information elsewhere suggests that examples of non-Protection System components include programmable logic controllers, computers, and the control functions of microprocessor relays.

Based on TANC's understanding of NERC's intent for this standard, we suggest that NERC modify the definition of RAS-owner that is provided in the standard's Applicability section to the following.

“RAS-owner - the Transmission Owner, Generator Owner, or Distribution Provider owns all or part of ***the non-Protection System components of*** *a RAS” (bold text is added to current proposed definition).*

TANC’s proposed modified definition would clarify that this standard and its requirements are not applicable to a Transmission Owner, Generator Owner, or Distribution Provider that doesn’t own any non-Protection System components of a RAS.

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:

Answer Comment:

Requirement R9: In conjunction with our comment under Q2 to replace TP with PC, while we agree that the RC is the appropriate entity to maintain the database, we suggest adding the Planning Coordinator to this requirement for RASs that have been planned and evaluated in the long-term planning timeframe. Some entities may have a need for planned RAS information for modeling.

We recommend that the standard should recognize that all RAS are not equal and therefore should not need the same level of design review (as per R1), performance requirement in case of RAS failure (as per 4.4), and operation analysis (as per R5). We suggest defining two or more “class” or “type” for RAS based on the impact of their misoperation or failure to operate on the system performance. Different class or type of RAS will then have different levels of design, performance and analysis requirements.

R8 and guidance provided in the supplemental material as written appears to overstep the direction provided by the SAR which states that the standard will address maintenance and testing on non-Protection System components of a RAS. Maintenance of Protection Systems installed as a RAS for BES reliability is clearly covered in PRC-005. The IESO is very concerned that there are different timeframes and duplicative testing for RAS components. In particular, the supplemental material provided is very confusing and appears to suggest duplicative testing compared to testing already required in PRC-005. The IESO suggests that all testing requirements for RAS should be contained in one standard. NERC PRC-005 applies to Protection Systems installed as Remedial Action Schemes for BES reliability. As such, all RAS Protective Relays, Communication Systems, Voltage and Current Sensing Devices Providing Inputs to Protective Relays, Control Circuitry, DC Supply, alarms and Automatic Reclosing Components are already included in PRC-005. Lastly, this requirement would force entities to perform testing on local area schemes; yet non-BES components are not subject to maintenance requirements under NERC PRC-005. Typing would be a good mythology to distinguish which RAS schemes should be subject to the strict maintenance requirements.

The IESO suggests deletion of the phase “including any identified deficiencies” in R5 because requirements R5.1 through R5.4 clearly define the necessary level of analysis required by the RAS-owner. Leaving this phrase in will lead to confusion over whether the proper operation of a “composite” RAS is considered a deficiency if one of the two redundant RAS suffer a component failure.

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer:

Answer Comment:

The California ISO supports the comments of the ISO/RTO Standards Review Committee

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:

Answer Comment:

The second version of PRC-005 was intended to include all testing and maintenance requirements from PRC-017, and facilitate the retirement of PRC-017. Requirement 8 of the current draft of this standard (PRC-012-2) includes testing and maintenance requirements related to those found in PRC-017-0. Additionally, Requirement 8 of PRC-012-2 expands on those found in PRC-017-0 by including non-Protection System components. We feel this requirement should not be included in PRC-012-2, and we request a clear description of the differences of the intended purpose of the proposed PRC-012-2 Requirement 8 and that of PRC-017-0/PRC-005-2. Furthermore, the remaining requirements of PRC-012-2 seem to be primarily focused on system planning, and consideration should be given to moving these to the TPL standard family.

Document Name:

Likes: 1 Nebraska Public Power District, 3, Eddleman Tony

Dislikes: 0

Andrew Gallo - Austin Energy - 6 -

Selected Answer:

Answer Comment:

City of Austin dba Austin Energy suggests the SDT add clarifying language to R8 to account for a RAS-owner who owns only part of a RAS. In doing so, the SDT may need to consider how a partial RAS-owner will be able “to verify the overall RAS performance.”

Document Name:

Likes: 0

Dislikes: 0

Dixie Wells - Lower Colorado River Authority - 5 -

Group Information

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Voter Information

Voter	Segment
Dixie Wells	5
Entity	**Region(s)**
Lower Colorado River Authority	

Selected Answer:

Answer Comment:

To address existing entity NERC registration in the ERCOT region, “Transmission Planner” should be replaced with “Transmission Planner (in the ERCOT Region this applies to the Planning Authority and /or Reliability Coordinator.)”

R4. Each Transmission Planner (in the ERCOT Region this applies to the Planning Authority and /or Reliability Coordinator) shall perform an evaluation of each RAS within its planning area at least once every 60- full- calendar- months and provide the RAS- owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether: *[Violation Risk Factor: Medium] [Time Horizon: Long- term Planning]*

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

The second version of PRC-005 was intended to include all testing and maintenance requirements from PRC-017, and facilitate the retirement of PRC-017. Requirement 8 of the current draft of this standard (PRC-012-2) includes testing and maintenance requirements related to those found in PRC-017-0. Additionally, Requirement 8 of PRC-012-2 expands on those found in PRC-017-0 by including non-Protection System components. We feel this requirement should not be included in PRC-012-2, and we request a clear description of the differences of the intended purpose of the proposed PRC-012-2 Requirement 8 and that of PRC-017-0/PRC-005-2. Furthermore, the remaining requirements of PRC-012-2 seem to be primarily focused on system planning, and consideration should be given to moving these to the TPL standard family.

Document Name:

Likes: 1 Nebraska Public Power District, 1, Cawley Jamison

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer:

Answer Comment:

The second version of PRC-005 was intended to include all testing and maintenance requirements from PRC-017, and facilitate the retirement of PRC-017. Requirement 8 of the current draft of this standard (PRC-012-2) includes testing and maintenance requirements related to those found in PRC-017-0. Additionally, Requirement 8 of PRC-012-2 expands on those found in PRC-017-0 by including non-Protection System components. We feel this requirement should not be included in PRC-012-2, and we request a clear description of the differences of the intended purpose of the proposed PRC-012-2 Requirement 8 and that of PRC-017-0/PRC-005-2. Furthermore, the remaining requirements of PRC-012-2 seem to be primarily focused on system planning, and consideration should be given to moving these to the TPL standard family.

Document Name:

Likes: 1 Nebraska Public Power District, 1, Cawley Jamison

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Texas RE seeks clarification on the following:

- If a RAS is implemented to run-back a generator due to a line loading trigger level, is the Generator Owner a RAS-owner by default? Or is it dependent upon the ownership of the components that are used (e.g., protective or auxiliary relays, communication systems, sensing devices, station DC, control circuitry, etc.)?
- In Requirement R5, is the responsibility associated with the each RAS-owner correct? Should that responsibility be the RAS-entity (in collaboration with all RAS-owners) to avoid multiple analysis activities which may result in conflicting results and/or CAPs? If one RAS-owner

finds a deficiency in another owner's portion of the RAS, how is that notification made?

- In Requirement R5 there is no notification of a deficiency to a RAS-owner. Is notification considered to be when a RAS-owner recognizes a deficiency in its part of the RAS? R6 references a notification but it is not clear in R5.

- Does the SDT consider "arming", whether it signals another party to act or is used in situational awareness, as an integral part of RAS operation? Some RAS designs include an "arming" phase (e.g., A RAS will "arm" if the amperage on line X measure 900 amps. If the amperage measures 920 amps the RAS will activate. In some designs, "arming" may signal action to be taken by another party is needed (e.g. generator runback to level X), and if the action is not taken the RAS may fully activate (e.g. trip generator).) In the Supplemental Material (and somewhat, but not totally, mirrored in the rationale for R5) there is the statement: "A RAS operational performance analysis is intended to: (1) verify RAS operation is consistent with implemented design; or (2) identify RAS performance deficiency(ies) that manifested in the incorrect RAS operation or failure of RAS to operate when expected." Failure of a RAS to arm, if designed to arm, is indicative that the design was improperly implemented.

- In Requirement R8, which entity responsible for coordinating the functional test for a multi-owner RAS that covers a wide area? The segmented approach referred to in the rationale may cover an individual RAS-owner's trip function or communications, but there needs to be an overall functional test of the logic that arms/disarms/activates the RAS, which may involve multiple RAS-owners. Texas RE recommends changing the requirement language to "RAS-owner, or RAS-entity as mutually agreed by the RAS-owners shall…". Also, a functional test should be required if there is a system change that affects one or more Elements that are monitored or operated as part of a RAS, in order to verify any logic changes. Requirements R1-R3 currently do not address functional testing, only the design. Texas RE recommends R8 indicate "proper operation of RAS" elements and not limit the functional test verification to non-Protection System components. Some Protection System components involved in the proper operation of a RAS may have an extended maintenance intervals and the RAS would not be functionally tested without including Protection System components. Overall RAS performance cannot be attained without functionally testing all aspects of the RAS.

Texas RE noticed an inconsistency between the requirement language and the RSAW. The requirement language of Requirement R5 states “Each RAS-owner shall” but the Note to Auditor in the Requirement R5 section of the RSAW indicates that a RAS-entity can provide the analysis. Registered entities are held accountable to the language of the requirement. Introducing the concept of a RAS-entity providing the information adds confusion. If the intent is for both the RAS-Owner and the RAS-entity to be able to analyze RAS performance and provide the results, Texas RE recommends changing the requirement language to “RAS-owner, or RAS-entity as mutually agreed by the RAS-owners analyze…”. Texas RE supports the idea of a RAS-entity doing the analysis.

Additionally, Texas RE recommends a requirement to report the degraded RAS to the RC. Texas RE noticed the referenced Standards/Requirements (i.e., Supplemental Material indicates PRC-001 R6 and TOP-001-2 R5) are either being retired or are not explicit enough to ensure that the reliability of the system is maintained for those who should have situational awareness. This is a perceived gap due to the current steady state of the standards.

Texas RE recommends Attachment 3 include the RAS-owner(s) as well as the RAS-entity. If Requirement R9 is left as “at a minimum”, that is all that will be done. Ownership is critical to know because of the responsibilities required in the majority of the Requirements (e.g., How will the TP provide results to owners without knowing all the owners?) The TP does not, generally, know the RAS-owners based on the ownership at the component level.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

· Hydro One Networks Inc. recommends that the standard should recognize that all RASs are not equal and therefore, should not be subject to the same level of design review (as per R1), performance requirements in case of RAS failure (as per 4.4), and operation analysis (as per R5). We suggest defining two or more "class" or "type" for RAS based on the impact of their misoperation or failure to operate on the system performance. Different classes or types of RAS will consequently have different levels of design, performance and analysis requirements associated with them. Hydro One Networks Inc. would like to emphasize that in the absence of a means of differentiation (via typing or classes of RAS), utilities will feel compelled to spend significant capital, for little or no material improvement to system reliability.

· Hydro One Networks Inc. believes that requirement R8 and guidance provided in the supplemental material appear to overstep the direction provided by the SAR, which states that the standard will address maintenance and testing on non-Protection System components of a RAS. Maintenance of Protection Systems installed as a RAS for BES reliability is clearly covered in PRC-005. Hydro One Networks Inc. further joins the NPCC with its concern over the different timeframes provided and duplicative testing for RAS components. In particular, the supplemental material provided is very confusing and appears to suggest duplicative testing compared to testing already required in PRC-

	005. Hydro One Networks Inc. agrees with the NPCC and suggests that all testing requirements for RAS should be contained in one standard. NERC PRC-005 applies to Protection Systems installed as Remedial Action Schemes for BES reliability. As such, all RAS Protective Relays, Communication Systems, Voltage and Current Sensing Devices Providing Inputs to Protective Relays, Control Circuitry, DC Supply, alarms and Automatic Reclosing Components are already included in PRC-005. Lastly, this requirement would force entities to perform testing on local area schemes; yet non-BES components are not subject to maintenance requirements under NERC PRC-005. Typing would be a good mythology to distinguish which RAS schemes should be subject to the strict maintenance requirements. · Hydro One Networks Inc. also agrees with the NPCC in suggesting the deletion of the phase “including any identified deficiencies” in R5 because requirements R5.1 through R5.4 clearly define the necessary level of analysis required by the RAS-owner. Leaving this phrase in would lead to confusion over whether the proper operation of a “composite” RAS is considered a deficiency if one of the two redundant RAS suffer a component failure.
Document Name:	
Likes:	0
Dislikes:	0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter	Segment
Carol Chinn	4
Entity	**Region(s)**
Florida Municipal Power Agency	

Selected Answer:

Answer Comment:

The roles and relationships between the RAS-entity and the RAS-owners could be made clearer throughout the standard. Overall, FMPA supports the drafting team’s approach, but there have been several comments submitted that should be considered before the standard is approved and would like to see outreach done *before* the next posting of the standard for comment and ballot.

Document Name:

Likes:	0
Dislikes:	0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Voter Information

Voter
Brian Van Gheem

Segment
6

Entity
ACES Power Marketing

Region(s)
NA - Not Applicable

Selected Answer:

Answer Comment:

(1) Requirement R9 requires the RC to update its RAS database annually. However, we believe the requirement should be rewritten to require the RC to develop and implement a process to conduct a review of its database and at what frequency. If a RAS-owner has not made any changes to functionality and system conditions and operating configurations are as expected, we feel this requirement is more of an administrative burden falling under Paragraph 81 Data Collection criteria.

(2) We question how a RC is expected to maintain a dated revision history as evidence for Requirement R9 when the context of this requirement is to update a database. We believe the requirement is more of an administrative burden falling under Paragraph 81 Data Collection criteria, and the requirement should be rewritten to require the RC to develop and implement a process to conduct a review of its database and at what frequency.

(3) We believe the evidence retention of this standard should identify retention periods for applicable entities and not limit retention just for TOs, GOs, and DPs.

(4) The VSLs for Requirements R1 and R3 currently have only a Severe VSL identified. We believe the VSL criteria for these requirements could be written on a sliding time scale based on the projected installation or retirement dates of a RAS.

(5) We believe the VSL criteria listed with many requirements is too condensed. We recommend incrementing the criteria for Requirement R4 by quarters instead of by months. Moreover, we recommend incrementing the criteria for Requirement R5 by months rather than by every ten days. We also recommend incrementing the criteria for Requirements R8 and R9 by quarters rather every thirty days.

(6) We have concerns that the SDT has introduced a new measure of time, the "full-calendar-month." This measure will cause confusion with implementation and during audits. Moreover, there is inconsistent uses of this time measure within the standard. The SDT uses 60-full-calendar-months in R4, but does not use the same measurement in R5 for 120-calendar days and R8 for six-calendar years. Should R5 be four-full-calendar-months and R8 be six-full-calendar-years? The rationale for "full-calendar months" is only specified within the RSAW of this Standard. We feel the SDT should remove the measure of "full-calendar months" and replace it with "calendar months" to be consistent with the other NERC standards.

(7) We thank you for this opportunity to comment on this standard.

Document Name:

Likes:	0
Dislikes:	0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

BPA believes R5's reporting to the RC of the correct operation of a RAS is unduly onerous without providing value. BPA analyzes all RAS operations. If we see a scheme that operates too frequently (this is very subjective), we evaluate that scheme to see if there is something that can be done to minimize the number of operations. BPA proposes this be deleted from the requirement.

Document Name:

Likes: 0

Dislikes: 0

Consideration of Comments

Project Name: 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes | PRC-012-2

Comment Period Start Date: 8/20/2015

Comment Period End Date: 10/5/2015

Associated Ballot: 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes PRC-012-2 IN 1 ST

There were 60 responses, including comments from approximately 155 different people from approximately 104 different companies representing 9 of the 10 Industry Segments as shown on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Howard Gugel (via email) or at (404) 446-9693.

The drafting team made the following changes to the draft standard and implementation plan based on stakeholder comments:

Reliability Standard PRC-012-2

Applicability

Replaced the Transmission Planner with the Planning Coordinator.

Consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns a RAS.

Requirements

Requirement R1

Made minor clarifying changes.

Requirement R2

Made a minor clarifying change.

Requirement R3

Restructured for clarity.

Requirement R4

Restructured for clarity and included the RAS-entity as well as each impacted Transmission Planner and Planning Coordinator to Part 4.2 to receive the results of the RAS evaluation.

Included a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. Inserted a footnote for additional explanation.

Requirement R5

Restructured for clarity and added "on a mutually agreed upon schedule" to allow longer periods for the RAS operational analysis to be performed. Also changed from "analyze" to "participate in analyzing" for consistency with other requirements.

Requirement R6

Revised to include "Identifying a deficiency in its RAS pursuant to Requirement R8" as an additional trigger for the development of a CAP.

Requirement R7

Revised for clarity and added "and when the CAP is completed" to Part 7.3 regarding notification of the RC.

Requirement R8

Revised to provide a twelve full calendar year test interval for all RAS designated as limited impact. Also changed from “perform” to “participate in performing” for consistency with other requirements.

Requirement R9

Revised time period from “once each calendar year” to “once every twelve full calendar months”.

Measures, VSLs, and Attachments

Revised to be consistent with and complement the revised requirements.

Rationale Boxes and Supplemental Material

Revised to complement the revised requirements and provide additional examples and insight.

Implementation Plan

Requested Retirements

Removed references to Version 0 standards.

Applicable Entities

Replaced the Transmission Planner with the Planning Coordinator.

Consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns a RAS.

Background and General Considerations

Revised to reflect issuance of FERC Order No. 818 approving the RAS standards and definition of “Remedial Action Scheme.”

Effective Date

Changed the implementation period of the standard from twelve (12) months to thirty-six (36) months to provide entities more time to establish the new working frameworks among RAS-entities, Reliability Coordinators, and Planning Coordinators.

Added clarifying language for the initial performance of obligations under Requirements R4, R8, and R9.

Questions

Requirements R1, R2, and R3 pertain to the submittal of Attachment 1 information to the Reliability Coordinator (RC) for the review of a RAS, the RC using Attachment 2 as a guide for performing the RAS review, and the RC approving the RAS prior to the RAS being placed in service. Question 1 is relevant to these activities.

1. RAS review and approval: Do you agree with the RAS review process outlined by Requirements R1, R2, and R3? If no, please provide the basis for your disagreement and an alternate proposal.

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

2. RAS Periodic Evaluations: Do you agree with the RAS planning evaluation process outlined by Requirement R4? If no, please provide the basis for your disagreement and an alternate proposal.

3. RAS Inadvertent Operation: Do you agree with Requirement 4 Part 4.3 and Attachment 1 which stipulates that RAS inadvertent operation due to a single component malfunction still satisfies the System performance requirements common to TPL-001-4 P1-P7 events listed in Parts 4.3.1-4.3.5? (Note that this requirement remains the same as PRC-012-0 R1.4 except for the allowance for designed-in security that would prevent RAS inadvertent operation for any single component malfunction). If no, please provide the basis for your disagreement and an alternate proposal.

4. RAS Single Component Failure: Do you agree with Requirement 4 Part 4.4 and Attachment 1 which stipulates that any RAS intended to satisfy System performance requirements in a TPL standard must still satisfy those requirements when experiencing a single component failure? (Note that this requirement remains unchanged from PRC-012-0 R1.3.) If no, please provide the basis for your disagreement and an alternate proposal.

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

5. Corrective Action Plans: Do you agree that the application of Requirements R6 and R7 would address the reliability objectives associated with CAPs? If no, please provide the basis for your disagreement and an alternate proposal.

6. Implementation Plan: Do you agree with the Implementation Plan? If no, please provide the basis for your disagreement and an alternate proposal.

7. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Requirements R1, R2, and R3 pertain to the submittal of Attachment 1 information to the Reliability Coordinator (RC) for the review of a RAS, the RC using Attachment 2 as a guide for performing the RAS review, and the RC approving the RAS prior to the RAS being placed in service. Question 1 is relevant to these activities.

1. RAS review and approval: Do you agree with the RAS review process outlined by Requirements R1, R2, and R3? If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6

Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: No

Answer Comment:

The NSRF propose revising R2 to explicitly include the engagement of any applicable Planning Coordinators with wording like, "Each Reliability Coordinator . . . shall in conjunction with impacted Transmission Planners and Planning Coordinators . . ." The inclusion of Transmission Planners and Planning Coordinators is appropriate because RASs are 'standing, automatic' schemes that are evaluated primarily in the planning horizon and by Transmission Planners. In general, Reliability Coordinators do not have planning horizon analysis information or expertise.

We further recommend that M2 and M3 be modified such that acceptable evidence can be a Reliability Coordinator sponsored peer review by impacted entities.

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

Acceptable evidence for Measure M2 is dated reports, checklists, or other documentation detailing the RAS review was performed, the aspect of "who" performed the review is not a factor. The drafting team declines to make the suggested change.

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:	Yes
Answer Comment:	Oncor Electric Delivery believes that it is a good idea to have an independent party review any RAS. However, 90 days for the review seems more reasonable since they are just reviewing the scheme. Additionally Oncor Electric Delivery believes the RAS information required in attachment 1 contains more than is necessary for a review and cannot always be obtained for every RAS. In fact, unless the RAS is an existing system during the review period there are usually no schematics to review so we do not believe it is appropriate to request schematic diagrams. The second bullet under General section I asks for "functionality of a new RAS", which would be

a relay functional diagram that depicts how the scheme works and that would be available during the review process.

Response: Thank you for your comments.

The time frame of four full calendar months is consistent with current utility and regional practices. The drafting team wrote the requirement to allow for time intervals longer or shorter than four full calendar months by including the phrase "mutually agreed upon schedule" among the affected parties. The drafting team declines to make the suggested change.

Attachment 1 lists information that is suppled to sufficiently define the electrical and physical location of a RAS. Schematic diagrams are listed as one example of information that may be useful but are not required. The reviewing RC will decide if any additional information is necessary beyond what the RAS-entity originally supplied on a case-by-case basis. The drafting team modeled the RAS information required in Attachment 1 after the current WECC and NPCC (WECC and NPCC combined represent approximately two-thirds of existing RAS in North America) design guides and review procedures documents which include details of the RAS design expectations and reviews. The drafting team maintains the level of detail specified in Attachment 1 is consistent with these common practices and declines to make the suggested change.

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3

Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Selected Answer: Yes

Chris Scanlon - Exelon - 1 -

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Selected Answer: Yes

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: Yes

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer: No

Answer Comment:

a. R1 references "each RAS-entity shall submit…", but there should only be one RAS-entity per RAS, is this correct?

b. The supplemental material of the Standard states that the RAS owners needs to select an RAS-entity or else the RC will select the RAS-entity. This language needs to be in the Standard if it's going to be enforceable.

c. For the designation of the RAS-entity between different owners, will NERC/FERC/Regions require a CFR or JRO agreement? And what happens if one of the RAS owners is not a NERC registered entity, i.e., not a functional entity? Please describe what evidence needs to be provided to show designation of responsibility to the RAS-entity.

d. Also, most, if not all, new RASs are developed, studied, and reviewed within the long-term Planning Horizon by PCs and TPs. Modifications/retirements to existing RASs have the potential to be developed in the Operating Horizon; therefore, Seminole suggests that R1 be broken up into two requirements, one addressing modifications/retirements which would be specific to the "Operations Planning Horizon" and the second addressing "new" RASs specific to the "Long-term Planning Horizon" and applicable to PCs as well.

e. Can the drafting team define all of the components of an RAS so that "ownership" can be determined, i.e., what equipment makes up an RAS?

Response: Thank you for your comments.

a. Yes, you are correct.

b. The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS.

c. The drafting team notes that a JRO and a CFR, provided for in Sections 507 and 508 of the NERC Rules of Procedure, respectively, are voluntary registration relationships that entities may employ to accomplish registration responsibilities. Among other options for sharing registration responsibility, the JRO and CFR registration relationships can be implemented on ad hoc bases depending on the entities' unique circumstances. Per the definition, a RAS-owner (now RAS-entity) will be a Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. Each of these functional NERC registrations are defined in the NERC Rules of Procedure. As such, the drafting team does not foresee a situation when a RAS-entity would not be a NERC registered entity.

d. Existing regional RAS reviews do not make any distinction between RAS conceived or modified by planning or operating groups. The drafting team does not see any reliability benefit in bifurcating the RAS review process in this manner and declines to make the suggested change.

e. The drafting team revised Item 1 in the Implementation Section of Attachment 1 to better describe RAS components. The RC will make the final determination regarding the RAS components during its review.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

A. It is unclear why R3 is not structured consistent to R1 even though both requirements are prerequisites for achieving the same objective of "placing a new or functionally modified RAS in service or retiring an existing RAS". Suggest restructuring R3 as follows for clarity and consistency: "Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, the RAS-entity shall address each issue identified by the RAS review (performed pursuant to Requirement R2) and obtain approval of the RAS from each reviewing Reliability Coordinator."

B. In R1, the RAS review falls within the purview of one or more RC's depending on "the area(s) where the RAS is located." What attributes define the location of a RAS? Should the RAS location comprise of only the station(s) where its remedial action logic processing device(s) is/are installed? Or would the RAS location also include the stations from where the various RAS inputs are telemetered to the logic processing device? Would it also include the station(s) at which the RAS output(s) – that is, remedial actions – are sent? Suggest that the standard provides clear guidance on what comprises the RAS location. Alternatively, suggest using a different RAS characteristic in R1 to avoid subjective and inconsistent interpretations of what comprises RAS location.

Response: Thank you for your comments.

A. The drafting team made the suggested change.

B. The drafting team maintains that the RAS location may cover multiple Reliability Coordinator Area(s) that contain any aspect of a RAS (e.g., inputs, outputs, logic, or equipment) that allows the RAS to operate as-designed. The drafting team declines to make the suggested change.

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:	Yes

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer:	Yes

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:	No
Answer Comment:	Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Response: Please see the drafting team's responses to the referenced comments.

David Greene - SERC - 1,10 - SERC

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Selected Answer: Yes

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer: Yes

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment: ATC proposes revising R2 to explicitly include the engagement of any applicable Planning Coordinators with wording like, "Each Reliability Coordinator........ shall in conjunction with any Planning Coordinators ...." The inclusion of Planning Coordinators is appropriate because RASs are 'standing, automatic' schemes that are evaluated primarily in the planning horizon and by Transmission Planners. In general, Reliability Coordinators do not have planning horizon analysis information or expertise.

Response: Thank you for your comment.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: No

Answer Comment: The Planning Coordinator is the correct function to determine where a RAS Scheme is required. The need for an RAS is determined from TPL studies and planned system performance. References to the Reliability Coordinator should be changed to Planning Coordinator. The NERC Functional Model defines the RC as being "The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." It is not responsible for the planning or installation of a Protection System. The NERC Functional Model does not support the RC as being the reviewer. The RC currently does not review nor have the authority to approve any other facility or protection system installation.

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the “flexibility” to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC’s Reliability Functional Model, Version 5, November 2009.

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment: To remove possible confusion, “on a mutually agreed upon schedule” should be changed to “on a mutually agreed upon schedule between Reliability Coordinators and RAS-entities.”

Response: Thank you for your comment.

The drafting team maintains that the requirement is clear, the RC and the RAS-entity are the only parties mentioned in the requirement. The drafting team declines to make the suggested change.

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Selected Answer: No

Answer Comment: The Planning Coordinator is the correct function to determine where a RAS Scheme is required. The need for a RAS is determined from TPL studies and planned system performance. The standard correctly provides the RC with an opportunity to participate in providing opinion. The NERC Functional Model defines the RC as being “The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.” It is not responsible for the planning or installing a Protection System. The NERC Functional Model does not support the RC as being the reviewer. The RC currently does not review nor have the authority to approve any other facility or Protection System installation. Clarification of R3 regarding approval of the RAS after all issues have been addressed should be made. The approval mentioned in R3 could be interpreted as an approval that each identified outstanding issue was addressed and not a complete formal approval of the RAS. If the RC is to perform the review, we suggest the following rewording for R3:

"Following the review performed pursuant to Requirement R2, the RAS-entity shall address each issue identified by the Reliability Coordinators participating in the review and obtain final approval(s) for the RAS from each Reliability Coordinator participating in the review, prior to placing a new or functionally modified RAS in service or retiring an existing RAS."

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional

Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Selected Answer: No

Answer Comment: The owner of any protection scheme should be responsible for the correct design and implementation of the scheme – RAS or not. Just like the design of switching to create a blackstart cranking path by a TOP in EOP-005-2, Requirement 6 must be verified by that TOP, the owner of the RAS should be held to the same expectation that the RAS is correctly designed and

	implemented. If the SDT still believes that some sort of review is required, then that review should be limited in scope to reviewing the generic content of the RAS design and not delve into the technical depth identified in some parts of Attachment 2. Using the criteria outline by the SDT in its recent webinar, in addition to the independence of the reviewer and geographic span, the team also mentioned "expertise in planning, protection, operations, equipment". The attributes of this expertise to the level expected do not currently exist in most RC organizations. RC's are primarily operating entities (and even then primarily in real-time) and not experts in planning (beyond the operating time frame), protection or equipment. Transmission Owners, Transmission Operators and Transmission Planners normally have that expertise. The FERC acknowledged the limited RC technical expertise in evaluating details of restoration plans in its Order 749, Paragraph 38 ("…basis on which a reliability coordinator rejects a restoration plan will necessarily be based on generic engineering criteria…"). The review of a RAS by an RC should not be held to a higher expectation due to similar limited expertise with the equipment and systems involved in a RAS. The "flexibility" for the RC granted in the requirement to designate a third party would seem to immediately invalidate the original assumptions that the RC has the compelling capability to adequately perform the review while meeting the SDT's characteristics of the reviewing entity. To allow this, while still requiring the RC to be responsible for the review, seems like an improper administrative burden and a potential compliance risk that the RC may assume because it had to find an entity more qualified than itself to perform the review. If an RC is not qualified to review all of the items in Attachment 2 then how can it be held responsible for the results of the review?

Regarding the designation of a third party reviewer, clarification needs to be made regarding what it means to “retain the responsibility for compliance.” Does this simply mean that the review takes place or that there is some implied resulting responsibility for the correct design and implementation that the RC is now accountable for.

Finally, also regarding the designation of a third party reviewer, is the term “third party” meant to be any entity not involved in the planning or implementation of the RAS?

The alterative to using the RC? Although there appears to be a movement to remove the RRO as a responsible entity from all standards, those organizations through their membership expertise and committee structures more closely match the characteristics stated by the SDT – expertise in planning/protection/operations/equipment, independence by virtue of the diversity of its members, wide area perspective, and continuity. If for some reason the SDT, believes that the RRO still should not be involved then an alternative could be the Planning Coordinator function which should have similar expertise to the Transmission Planners that are to specify/design a RAS per the functional model yet would have some independence which the SDT is looking for.

Response: Thank you for your comments.

The drafting team agrees that the owner of the RAS is responsible for the comprehensive design and detailed implementation of its RAS; however, the drafting team believes that an additional layer of review of the RAS should be performed. Because the RAS-owner (now RAS-entity) is the party that will ultimately design and implement its protection scheme, the RAS-entity is not an appropriate party to perform an independent review of its own system. Rather, in its original draft, the drafting team asserted that the Reliability Coordinator (RC), an entity with a requisite level of expertise and geographically expansive visibility, should perform a review of the RAS. Further, the drafting team maintains that, because results from previous reviews have shown that utilizing these metrics is both effective and efficient, the comprehensive RAS review to be performed by the RC that is currently performed by the regional entities should include the level of detail described in Attachments 1 and 2.

The drafting team is charged with assigning the requirements of the new standard to the specific users, owners, and operators of the Bulk-Power System while incorporating the reliability objectives of all the RAS/SPS-related standards. In drafting this standard, the team has worked diligently to minimize the changes that will be required from the existing processes. The drafting team maintains that the RC may, at its discretion, request information or assistance from other entities to perform the RAS review. This “flexibility” to request assistance from a third party allows the RC to perform a more robust review of the RAS if that party has a particular piece of information or can provide unique assistance. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform that review. To the contrary, this ability ensures a more effective RAS review. The drafting team explains in the Rationale for Requirement R2 that the RC “will retain the responsibility for compliance with this requirement” according to the standard’s explicit applicability to the RC.

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment: On the whole, Reclamation agrees with the RAS review process outlined in Requirements R1–R3. However, Reclamation believes that RAS-owners should also be listed in Attachment 1 and Attachment 3 and should be notified of all RAS-entity communications with the Reliability Coordinator (RC). Reclamation does not believe that the RAS-entity should be able to release technical information about a RAS-owner's equipment without the knowledge of the RAS-owner.

Response: Thank you for your comments.

The drafting team maintains that each RAS-owner (now RAS-entity) would participate in producing the Attachment 1 data for a new or functionally modified RAS being submitted for review by the RAS-entity. The consolidation of the terms RAS-owner and RAS-entity effectively addresses your Attachment 3 comment.

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: No

Answer Comment: Florida Power & Light appreciates the efforts of the Standard drafting Team in consolidating the existing RAS-related Standards into one Standard (PRC-012), however we disagree with the assertion that the Reliability Coordinator (RC) is the best choice to review RAS's for new or continued implementation. The RC is responsible for the operation rather than the planning of the BES. RAS design and approval is best performed at the planning level. The Planning

Coordinator is responsible for coordinating transmission plans and protection systems and we believe more appropriate to review, approve and maintain the RAS database.

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Selected Answer: No

Answer Comment: The ISO/RTO Council Standards Review Committee (“SRC”) agrees that the RC should have to approve the use of RAS. Pursuant to the Functional Model, the RC does not have the authority to approve relay schemes. Nonetheless, it is important that the RC be informed of and understand how the RAS impacts the topology of its area of authority, identify and communicate any reliability issues to the RAS proponents, and coordinate with the RAS Entity regarding the in-service date and time of the RAS. We further recommend that M2 and M3 be modified such that acceptable evidence can be a Reliability Coordinator sponsored peer review with impacted Transmission Planners and Planning Coordinators.

Therefore, the SRC proposes that Requirement R3 be revised to:

R3. Following the review performed pursuant to Requirement R2, the RAS-entity shall address each identified issue and obtain concurrence from the Reliability Coordinator that all identified issues are resolved prior to placing a new or functionally modified RAS in service or retiring an existing RAS.

While the SRC is not opposed to a guideline regarding the performance of RAS evaluations, Attachment 2 is overly prescriptive and does not allow for impacted entities to utilize their operational experience and engineering judgment. The SRC recommends that the introductory paragraph to Attachment 2 be revised to provide greater flexibility regarding RAS evaluations. The following revisions are suggested:

The following checklist provides reliability related considerations for the Reliability Coordinator to consider for inclusion in its evaluation for each new or functionally modified2 RAS. The RC should utilize the checklist to determine those considerations that are applicable to the RAS evaluation being performed; however, RAS evaluations are not limited to the checklist items and the RC may request additional information on any reliability issue related to the RAS.

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

Acceptable evidence for Measure M2 is dated reports, checklists, or other documentation detailing the RAS review was performed, the aspect of "who" performed the review is not a factor. The drafting team declines to make the suggested change.

Please see the revision to Requirement R3 in the draft standard.

Please see the Supplemental Material section of the standard for the technical justification of Attachment 2. It reads: Attachment 2 is a checklist provided to assist the RC in identifying reliability considerations generally relevant to aspects of RAS design and implementation, and also for the purpose of facilitating consistent reviews continent-wide for each RAS to be installed or functionally modified. Most of the checklist items should be applicable to most RAS. There may be checklist items that are not applicable to a given RAS in which case they may be noted as not applicable and skipped in the RC review. Depending on the specifics of the RAS under review, it is possible that other reliability considerations may be identified during the review. Any other reliability considerations, along with their resolution with respect to the particular RAS under review, should be documented along with the Attachment 2 items that were applicable to the specific RAS under review.

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment: See comment in no. 7.

Response: Please see the drafting team's responses to the referenced comments.

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment: With regard to R1, the RAS entity is not typically qualified to provide some of the information required in Attachment 1, such as Sections II.3, II.4, II.5, and II.6. This information is typically developed by Planning Coordinator (PC) or

Transmission Planner (TP). RAS owners typically only implement the RAS as functionally required by the PC or TP. It is noted that the Planning Coordinator is not listed as an applicable entity and should be.

The Planning Coordinator is the correct function to determine where a RAS Scheme is required. The need for an RAS is determined from TPL studies and planned system performance. The standard correctly provides the RC with an opportunity to participate in providing opinion. The NERC Functional Model defines the RC as being "The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." It is not responsible for the planning or installation of a Protection System. The NERC Functional Model

does not support the RC as being the reviewer. The RC currently does not review nor have the authority to approve any other facility or protection system installation. Clarification of R3 regarding approval of the RAS after all issues have been addressed should be made. The approval mentioned in R3 could be interpreted as an approval that each identified outstanding issue was addressed not complete formal approval of the RAS. If the RC is to perform the review, we suggest the following:

R3- Following the review performed pursuant to Requirement R2, the RAS-entity shall address each issue identified by the Reliability Coordinators participating in the review and obtain final approval(s) for the RAS from each Reliability Coordinator participating in the review, prior to placing a new or functionally modified RAS in service or retiring an existing RAS.

With regard to R3, some of the identified issues would be most appropriately addressed by the PC or TP, especially the items in Section II of Attachment 1. It is inappropriate for RAS entity to assume compliance responsibility for addressing each identified issue. The RAS owner for the RAS issues should be the responsible entity.

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

Acceptable evidence for Measure M2 is dated reports, checklists, or other documentation detailing the RAS review was performed, the aspect of "who" performed the review is not a factor. The drafting team declines to make the suggested change.

Please see the revision to Requirement R3 in the draft standard.

Please see the Supplemental Material section of the standard for the technical justification of Attachment 2. It reads: Attachment 2 is a checklist provided to assist the RC in identifying reliability considerations generally relevant to aspects of RAS design and implementation, and also for the purpose of facilitating consistent reviews continent-wide for each RAS to be installed or functionally modified. Most of the checklist items should be applicable to most RAS. There may be checklist items that are not applicable to a given RAS in which case they may be noted as not applicable and skipped in the RC review. Depending on the specifics of the RAS under review, it is possible that other reliability considerations may be identified during the review. Any other reliability considerations, along with their resolution with respect to the particular RAS under review, should be documented along with the Attachment 2 items that were applicable to the specific RAS under review.

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: No

Answer Comment:

As Dominion stated in its previous comments, we believe that RAS should be reviewed and approved in both the planning and operating horizons by designated entities within whose area(s) the Facility (ies) the RAS is designed to protect reside.

Dominion suggests the following specific changes to R1: Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity shall submit the information identified in Attachment 1 for review to the Reliability Coordinator(s) **and Transmission Planner(s) within whose respective** area(s) the **Element(s) or Facility(ies)** for which the RAS is **designed to protect is (are)** located..

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the “flexibility” to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Selected Answer: No

Answer Comment: See the comment in #7.1. In addition, the Transmission Planner should be a required participant in developing Attachment 1 and at least be responsible for Section II in Attachment 1. Finally, the obligation in R3 that a RAS-entity address issues identified pursuant to R2 is incomplete. R3 should also place compliance obligations on the Transmission Planner and the RAS-owners to participate in addressing any issues under R3.

Response: Thank you for your comments.

Please see the drafting team's responses to the referenced comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

Please see the revision to Requirement R3 in the draft standard.

Please see the Supplemental Material section of the standard for the technical justification of Attachment 2. It reads: Attachment 2 is a checklist provided to assist the RC in identifying reliability considerations generally relevant to aspects of RAS design and implementation, and also for the purpose of facilitating consistent reviews continent-wide for each RAS to be installed or functionally modified. Most of the checklist items should be applicable to most RAS. There may be checklist items that are not applicable to a given RAS in which case they may be noted as not applicable and skipped in the RC review. Depending on the specifics of the RAS under review, it is possible that other reliability considerations may be identified during the review. Any other reliability considerations, along with their resolution with respect to the particular RAS under review, should be documented along with the Attachment 2 items that were applicable to the specific RAS under review. Please see the revised Applicability section of the standard for the new description of a RAS-entity.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The RAS-entity is the best-suited entity to address any identified issues per Requirement R3. The drafting team maintains that the RAS-entity has the “flexibility” to request information or assistance from relevant entities (third parties).

Likes:	4	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla PSEG - PSEG Fossil LLC, 5, Kucey Tim PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
Dislikes:	0	

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10

David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Selected Answer: No

Answer Comment:

Regarding Requirement R1, the RAS-entity is not typically qualified to provide some of the information required in Attachment 1, such as Sections II.3, II.4, II.5, and II.6. This information is typically developed by the Planning Coordinator (PC) or Transmission Planner (TP). RAS-owners typically only implement the RAS as functionally required by the PC or TP. The Planning Coordinator should be listed as an applicable entity.

The Planning Coordinator is the correct function to determine where a RAS

Scheme is required. The need for a RAS is determined from TPL studies and planned system performance. The standard correctly provides the RC with an opportunity to participate in providing opinion. The NERC Functional Model defines the RC as being "The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." It is not responsible for the planning or installation of a Protection System. The NERC Functional Model does not support the RC as being the reviewer. The RC currently does not review nor have the authority to approve any other facility or protection system installation. Clarification of R3 regarding approval of the RAS after all issues have been addressed should be made. The approval mentioned in R3 could be interpreted as an approval that each identified outstanding issue was addressed not complete formal approval of the RAS. If the RC is to perform the review, we suggest the following:

R3- Following the review performed pursuant to Requirement R2, the RAS-entity shall address each issue identified by the Reliability Coordinators participating in the review and obtain final approval(s) for the RAS from each Reliability Coordinator participating in the review, prior to placing a new or functionally modified RAS in service or retiring an existing RAS.

Regarding Requirement R3 some of the identified issues would be most appropriately addressed by the PC or TP, especially the items in Section II of Attachment 1 as mentioned earlier. It is inappropriate for the RAS-entity to assume compliance responsibility for addressing each identified issue. The RAS-owner for the RAS issues should be the responsible entity.

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The RAS-entity is the best-suited entity to address any identified issues per Requirement R3. The drafting team maintains that the RAS-entity has the "flexibility" to request information or assistance from relevant entities (third parties).during the review. Any other reliability considerations, along with their resolution with respect to the particular RAS under review, should be documented along with the Attachment 2 items that were applicable to the specific RAS under review.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Answer Comment: ERCOT supports the comments submitted by the ISO/RTO Council.

Response: Thank you for your comments.

Please see the drafting team's responses to the referenced comments.

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: No

Answer Comment: PJM supports the comments submitted by the ISO/RTO Council.

Response: Thank you for your comments.

Please see the drafting team's responses to the referenced comments.

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -	
Selected Answer:	Yes
Eric Olson - Transmission Agency of Northern California - 1 -	
Selected Answer:	Yes
Leonard Kula - Independent Electricity System Operator - 2 -	
Selected Answer:	No
Answer Comment:	R1, R2 and R3 do not differentiate between the functional aspects and design aspects of RAS. The functional requirements for a RAS, i.e. system conditions and triggering contingencies for which RAS is required as well as RAS actions to meet system performance requirement (as per TPL-001-4), are studied and identified by Transmission Planner and/or Planning Coordinator and not by the RAS owner/entity. The RAS owner/entity designs the RAS after TP or PC determines the functional requirements. The information listed in part II of attachment 1 is about functional requirements and can be provided by TP or PC. Most of the information listed in part I is repeat of part II. The rest, e.g., maps, one-line diagrams, in-service date, etc., can also be provided by TP or

PC who determined the functional requirements. The information in part III, which is related to the RAS design, is provided by the RAS owner/entity. RAS owners typically only implement the RAS as functionally required by the PC or TP. It is noted that the Planning Coordinator is not listed as an applicable entity and should be. With regard to R3, some of the identified issues would be most appropriately addressed by the PC or TP, especially the items in Section II of Attachment 1.

We suggest that R1, R2 and R3 and the related attachments be split in two parts: a) functional aspects, where TP or PC will be required to determine the functional requirements of the RAS and provide relevant information to RC for review, and b) design aspects, where RAS owner/entity will be required to design the RAS to meet those functional requirements and provide relevant information to RC for review.

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the “flexibility” to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The RAS-entity is the best-suited entity to address any identified issues per Requirement R3. The drafting team maintains that the RAS-entity has the "flexibility" to request information or assistance from relevant entities (third parties).during the review. Any other reliability considerations, along with their resolution with respect to the particular RAS under review, should be documented along with the Attachment 2 items that were applicable to the specific RAS under review.

Richard Vine - California ISO - 2 -

Selected Answer: No

Answer Comment:

The California ISO supports the comments of the ISO/RTO Standards Review Committee

Response: Thank you for your comments.

Please see the drafting team's responses to the referenced comments.

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Dixie Wells - Lower Colorado River Authority - 5 -

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Selected Answer: Yes

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Selected Answer: Yes

Answer Comment: We agree with the checklist for the Reliability Coordinator to receive the proper information pertaining to the RAS and conducting a proper analysis. Additionally, we commend the drafting team for addressing the timing requirements in the Requirement R3 Rationale Box. We feel this will give the industry amply of enough time to address any issues identified by the Reliability Coordinator through their analysis.

Response: Thank you for your support.

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:	No
Answer Comment:	Florida Power and Light appreciates the efforts of the Standard Drafting Team in consolidating the exsiting RAS-related Standards into one Standard - PRC-012-2, however we disagree with the assertion that the Reliability Coordinator (RC) is the best choice to review the RAS's for new and continued implementation. The RC is responsible for the operation rather than the planning of the BES. RAS design and approval is best done at the Planning level. The Planning Coordinator is responsible for coordinating transmission plans and protection systems and we believe more appropriate to review, approve, and maintain the RAS database.

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Yes

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment: In Requirement R3, the term “shall address” does not necessarily indicate the issue must be resolved as the Supplemental Material indicates. Texas RE recommends strengthening the requirement language to “shall resolve” or “shall implement”.

Response: Thank you for your comment.

The drafting team made the suggested change.

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Selected Answer: No

Answer Comment: 1. RAS review should be conducted by the Planning Coordinator and not the Reliability Coordinator. Oversight of the wide-area in the planning horizon is the job of the Planning Coordinator. This will be a significant amount of extra work for the RCs who should be focused on near-term operational reliability.

2. R1 should state a time frame the data should be submitted to the RC, such as four month prior to implementation of the RAS. Otherwise, the burden will be placed on the RC to conduct the study on the RAS-entities schedule.

3. There is no requirement to notify impacted neighboring entities. When a

RAS is implemented it can have a significant impact on neighboring entities. Neighboring entities need to have an opportunity to study the impact of the RAS.

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the “flexibility” to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC’s Reliability Functional Model, Version 5, November 2009.

The drafting team maintains that it is not necessary to specify how far in advance of implementation the RAS-entity must provide Attachment 1 data to the reviewing RC. Expeditious submittal of this information is in the interest of each RAS-entity to effect a timely implementation.

As noted above, the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. The drafting team contends that other Reliability Standards such TPL-001-4 provide avenues for neighboring entities to be notified well in advance of a new or modified RAS being implemented.

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:	No
Answer Comment:	R1, R2 and R3 do not differentiate between the functional aspects and design aspects of RAS. The functional requirements for a RAS, i.e. system conditions and triggering contingencies for which RAS is required as well as RAS actions to meet system performance requirements (as per TPL-001-4), are studied and identified by the TP and/or PC and not by the RAS owner/entity. The RAS owner/entity designs the RAS after the TP or PC determines its functional requirements. Therefore, the information listed in part II of attachment 1 is about functional requirements and can only be provided by a TP or PC in most instances. Most of the information listed in Part I is repeated in Part II. The remaining information listed, e.g., maps, one-line diagrams, in-service date, etc., can also be provided by the TP or PC, who determines the functional

	requirements. The information in Part III, which is related to the RAS design, is provided by the RAS owner/entity. Hydro One Networks Inc. suggests that R1, R2 and R3 and the related attachments be split in two parts: a) functional aspects, where the TP or PC will be required to determine the functional requirements of the RAS and provide relevant information to the RC for review, and b) design aspects, where the RAS owner/entity will be required to design the RAS to meet those functional requirements and provide relevant information to the RC for review. In addition, it is inappropriate for the RAS entity to assume compliance responsibility for addressing each identified issue. The RAS owner for the RAS issues should be the responsible entity; this would be more in agreement with the assignment of accountabilities in R6. Please also note our following comments with respect to relaxing the design review for a class of RAS.

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the “flexibility” to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The RAS-entity is the best-suited entity to address any identified issues per Requirement R3. The drafting team maintains that the RAS-entity has the "flexibility" to request information or assistance from relevant entities (third parties).during the review. Any other reliability considerations, along with their resolution with respect to the particular RAS under review, should be documented along with the Attachment 2 items that were applicable to the specific RAS under review.

Likes:	1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes:	0	

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer: No

Answer Comment:

R2 has an option of a four month schedule or a mutually agreed upon schedule. It is understood that setting a goal for a review within the operations time-frame is important, but it seems like the standard is trying to achieve two separate goals at once.

The first goal is to review the proposed change to determine whether it involves a CAP and identifies any current risks to reliability of the system which, as identified in the standard, might require use of System operating limits until the CAP is complete. This review needs to be completed quickly to minimize risk to the BES, but requires much less effort than a full review of the performance of the new RAS. In this instance four full-calendar months would seem to be too long of a time period.

The second goal is to complete the full review from a planning perspective. Each region already has a review and approval process in place. It seems arbitrary and unnecessary to impose the 4 month requirement rather than allowing the RC to follow a schedule or process it has already established. In this instance the four months would seem too short a time period in many cases due to the way these reviews are conducted (and by whom they are conducted) – so long as the risk to the BES reliability is already understood up-front, there is no reason to rush this portion of the work. In many cases, the RC in question may not possess the necessary staff / skills to perform what is required in Attachment 2, and may need to retain the services of others (consultants or perhaps area PCs or TPs), which will take time.

FMPA believes both issues could be resolved if R2 separated the near-term need to quickly assess BES reliability risk in the Operating Horizon from the long-term need to assess the details of the performance of the proposed scheme – particularly in cases where the proposed change is due to an identified issue with a subsequent CAP. Doing this first step on fast track would then allow each RC to define the schedule for the remaining review as per their regional practices.

Also, it would be beneficial to include all RAS-owners and their contact information in the RAS database.

Response: Thank you for your comments.

The time frame of four full calendar months is consistent with current utility and regional practices. The drafting team wrote the requirement to allow for time intervals longer or shorter than four full calendar months by including the phrase "mutually agreed upon schedule" among the affected parties. The RAS review associated with a CAP could and probably would require less than the four full calendar months. The drafting team disagrees that there is a reliability risk during the time interval associated with the CAP development though completion of the CAP because the Reliability Coordinator will require the RAS-entity to modify operating procedures, System configuration, generation dispatch, or employ other methods to alleviate the deficient RAS. The RAS review associated with new or functionally modified RAS is a more comprehensive review that entail the design, operations, and testing of the RAS. The drafting team declines to make the suggested change.

The drafting team modified the description of RAS-entity and eliminated RAS-owner. With this revised description, each RAS-entity (Transmission Owner, Generator Owner, or Distribution Provider) will be specifically identified in Attachments 1 and 3.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name:	ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Selected Answer: No

Answer Comment: (1) We question why the RC was selected as the reviewing entity in this context. RC System Operators are not required to be "familiar with" (Reliability Standard PRC-001) or "have knowledge of" (proposed Reliability Standard TOP-009) the purpose and limitations of a RAS. Moreover, after the RC has conducted its initial review (Requirement R2) and the RAS-entity has addressed the identified issues, there is no timeframe required for the RC to conduct a final review for approval. We suggest rewording Requirement R3 to require both the RAS-entity and the RC to address each identified issue within a mutually agreed upon timeframe and concluded by a final RC review. Documentation regarding an approval of the RC following its final review should then be listed as acceptable evidence in Measure M3.

(2) We would also like the drafting team to state that an existing SPS will not need to go through the RC approval process even though the new definition of RAS could be applied as a new RAS device. The standard is unclear regarding which equipment will need to go through the RC approval process, existing SPS/RAS or new/changed RAS equipment? One possible solution is to state that all SPS and RAS equipment that are in service on the effective date of the proposed standard are considered RAS going forward and will not be required to go through the RC approval process.

Response: Thank you for your comment.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009. As the drafting team stated in the Rationale and Supplemental Material section of the standard, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that it is not necessary to specify how far in advance of implementation the RAS-entity must provide Attachment 1 data to the reviewing RC. Expeditious submittal of this information is in the interest of each RAS-entity to effect a timely implementation. In turn, the RC is well aware of the issues that the RAS is intended to solve, as well as the implications to the RAS-entity's schedule for delays. It is in the interest of the reviewing RC to expeditiously acknowledge when reliability issues are resolved so that the larger solution (the RAS) can be implemented. The drafting team declines to make the suggested change to the Requirement R3.

Requirement 1 is applicable to new or functionally modified RAS. Existing RAS will not need to go through the RC approval process unless they require functional modification. The drafting team declines to make the suggested change.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment: BPA believes R2's timeline of four-full-calendar months for RC review of RAS submission is too generous; it is inconsistent with regional practice. BPA proposes two weeks as appropriate, with less potential negative impact. The schedule should be short enough to accommodate the needs of the RAS owners and the "mutually agreed upon schedule" should apply if more time is needed.

Response: Thank you for your comment.

The time frame of four full calendar months is consistent with current utility and regional practices. The drafting team wrote the requirement to allow for time intervals longer or shorter than four full calendar months by including the phrase "mutually agreed upon schedule" among the affected parties. The drafting team declines to make the suggested change.

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

2. RAS Periodic Evaluations: Do you agree with the RAS planning evaluation process outlined by Requirement R4? If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer: Yes

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	**Entity**	**Region**	**Segments**
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5

Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: No

Answer Comment:

For R4, we propose revised wording to explicitly include any applicable Planning Coordinators with wording like, ". . . provide the results including any identified deficiencies to the RAS-owner(s), the reviewing Reliability Coordinators(s) and impacted Transmission Planners and Planning Coordinators."

Again, the inclusion of impacted Transmission Planners and Planning Coordinators is appropriate because these entities will generally have the best planning horizon information and expertise to review the evaluation.

Response: Thank you for your comments.

The drafting team revised the requirement to make the Planning Coordinator the responsible entity for performing the periodic evaluations.

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Selected Answer: Yes

Chris Scanlon - Exelon - 1 -

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Selected Answer: Yes

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment: We agree the Transmission Planner should periodically evaluate each RAS but there needs to be a mechanism by which the RAS-owners are required to share the RAS information with the Transmission Planner.

Response: Thank you for your comment.
The drafting team revised the requirement to make the Planning Coordinator (PC) the responsible entity for performing the periodic evaluations and requiring the PC to provide the results of the RAS evaluation to each reviewing Reliability Coordinator and each impacted Transmission Planner and RAS-entity.

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: No

Answer Comment: The process is not clear about the responsibility for a RAS which is activated in multiple Transmission Planner areas such as WECC-1. The standard should clearly specify whose responsibility it is to perform technical studies. APS suggests the following language:

"For a RAS which is activated in multiple Transmission Planning areas, a mutually agreed upon Transmission Planner of one of the multiple Transmission Planning areas shall perform an evaluation of the RAS at least once every 60-full-calendar-months and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies."

Response: Thank you for your comment.

The drafting team revised the requirement to make the Planning Coordinator (PC) the responsible entity for performing the periodic evaluations. The drafting team notes that the existing wording of the requirement allows the individual PCs to perform the evaluation of RAS within its own planning area, and also allows coordination of all relevant PCs to perform a joint evaluation of RAS that span multiple PC areas.

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer: No

Answer Comment:

a. For R4, can the TP merely provide the data to the RAS owners and the RAS-entity report the information to the RC?

b. In R4.2, please give additional detail as to what "adverse interactions" cover?

Response: Thank you for your comment.

The drafting team asserts that the results of the periodic evaluation should go directly to the Reliability Coordinator because if there is a deficiency identified in the RAS functionality, a change in System operations may be required. The drafting team maintains that adverse interactions covers inadvertently activating other RAS, mis-coordinating with Protection Systems or control systems.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:	No
Answer Comment:	The rationale and/or technical guidance does not make a convincing case for why the periodic evaluation of RAS must be a planning horizon analysis, and thus suited to be performed by Transmission Planner. As currently drafted, R4 seems to have an underlying premise that the periodic evaluation needs to be performed for the near-term planning horizon, which makes the periodic evaluation akin to the typical (future year) planning studies performed by Transmission Planner. However, the rationale for R4 does not provide any justification for the above. In fact, performing a planning horizon analysis is inconsistent with, if not contradictory to, the following reliability need stated in the rationale “A periodic evaluation is needed because (material) changes in system topology or operating conditions that have occurred since the previous RAS evaluation – or initial review – was completed…” Doesn’t this imply that the periodic RAS evaluation is for past changes, not the future

planned changes? If so, wouldn't the periodic RAS evaluation be more akin to Operational Planning Analysis (OPA) in the operating horizon? Is there a reason why an OPA would not be able to comprehensively address items 4.1 – 4.4 required for periodic RAS evaluation? We note that the existing R4 rationale makes an inadequate claim that "items required to be addressed in the evaluation are planning analyses", which is a weak basis for concluding that "consequently, the Transmission Planner is the functional entity best suited to perform the analyses." Based on all the above reasons, we contend that the reliability objectives of periodic RAS evaluation are more effectively achieved based on an operating horizon analysis like OPA. Therefore, the periodic RAS evaluation lends itself better to be performed by the Transmission Operator (or perhaps even the Reliability Coordinator).

Response: Thank you for your comment.

The evaluation in Requirement R4 is intended to verify the effectiveness and coordination of the RAS for the current System conditions as well as to verify that, if a RAS single component failure or single component malfunction were to occur, requirements for BES performance would continue to be satisfied. Operational Planning Analysis (OPA), by definition, look forward rather than backwards. The drafting team declines to make the suggested change.

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment: Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Response: Please see the drafting team's responses to the referenced comments.

David Greene - SERC - 1,10 - SERC

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments

Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Selected Answer: Yes

Answer Comment: Suggest clarifying in R4 that the evaluation is a technical evaluation as stated below:
Each Transmission Planner shall perform a **technical evaluation (planning analyses)** of each RAS within its planning area at least once every 60-full-calendar-months and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies.

Response: Thank you for your comment.

The drafting team declines to make the suggested change.

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer:	Yes

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:	No
Answer Comment:	For R4, ATC proposes revising the wording to explicitly include any applicable Planning Coordinators with wording like, ". . . provide the results including any identified deficiencies to the RAS-owner(s), the reviewing Reliability Coordinators(s) and any applicable Planning Coordinators." Again, the inclusion of Planning Coordinators is appropriate because the Transmission Planner evaluation will be for the planning horizon and Planning Coordinators will generally have the best information and expertise to review the evaluation.

Response: Thank you for your comments.

The drafting team revised the requirement to make the Planning Coordinator the responsible entity for performing the periodic evaluations.

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer:	No
Answer Comment:	The RAS-entity would be more appropriate to be specified in R4 instead of the RAS-owner

Response: Thank you for your comment.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS.

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer:	Yes

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Selected Answer:	No
Answer Comment:	The RAS-entity would be more appropriate to be specified in R4 instead of the RAS-owner.

Response: Thank you for your comment.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Selected Answer: Yes

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

David Kiguel - David Kiguel - 8 -

Selected Answer: No

Answer Comment: While generally supportive of this standard, I have concerns over assigning longer term assessment to Transmission Planner rather than to the Planning Coordinator.

Response: Thank you for your comment.

The drafting team revised the requirement and the Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4. The PC is the functional entity best suited to perform this evaluation because they have a wide-area planning perspective.

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -	
Selected Answer:	Yes

Anthony Jablonski - ReliabilityFirst - 10 -	
Selected Answer:	No
Answer Comment:	1. i. It is unclear why the Transmission Planner would provide results of the evaluation to each of the RAS-owner(s) and not the RAS-entity. A RAS typically operates as a single scheme and thus the RAS-entity can coordinate with all the RAS-owners regarding such evaluation results. ii. ReliabilityFirst currently reviews each SPS at least once every five years for compliance with our Regional Criteria in accordance with fill-in-the-blank NERC standard PRC-012, Requirement R1. ReliabilityFirst has concerns with the 60 month review cycle in Requirement R4 as there may be instances in which a SPS which was reviewed by RF in the 2000 timeframe could theoretically not be reviewed until the 2020 timeframe. ReliabilityFirst believes a potential gap of 10 years in

between reviews may have reliability impact. In order to prevent such a potential gap, ReliabilityFirst recommends the following recommendation for consideration:

a. Each Transmission Planner shall perform an evaluation of each RAS within its planning area at least once every 60-full-calendar-months **[since its last evaluation]** and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether:

Response: Thank you for your comment.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS.

The drafting team revised the requirement. The Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4 and the RAS-entity will be provided the results by the PC. The PC is the functional entity best suited to perform this evaluation because they have a wide-area planning perspective.

The drafting team disagrees that there will be any reliability impact during the transition period. The analyses required in Requirement R5 for all operations of the RAS will provide the reliability assurance you reference.

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Name:	IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Selected Answer: No

Answer Comment: Many Transmission Owner organizations also perform the transmission planning function and as such, are also registered as the Transmission Planners (for the assets that they own). The SRC believes that a proper, unbiased evaluation of RAS performance should be conducted by an entity that is not in the same organization as the TO and has a broader perspective, which is important because RAS's intended function and operational impact may affect more than one TO and TP. The SRC respectfully asserts that, given the importance of independence and a wide-area perspective, the Planning Coordinator is a more appropriate entity to perform Requirement R4 . The SRC therefore suggests replacing the TP with the PC or, at a minimum, requiring a review of results and provision of feedback by the Planning Coordinator to the Transmission Planner. This proposal is consistent with the basis for assigning R2 to the RC rather than the TOP.

Response: Thank you for your comment.

The drafting team revised the requirement. The Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4 and is required to provide the results of the RAS evaluation to each reviewing Reliability Coordinator and each impacted Transmission Planner and RAS-entity. The PC is the functional entity best-suited to perform this evaluation because they have a wide-area planning perspective.

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment: See comment in no. 7.

Response: Please see the drafting team's response to the referenced comment.

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment: The RAS-entity would be more appropriate to be specified in R4 instead of the RAS-owner.

The RAS-entity and the RAS-owner should be provided with the result of the review. The PC may be more appropriately qualified to review certain RAS than the TP.

Response: Thank you for your comment.

The drafting team revised the requirement. The Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4 and is required to provide the results of the RAS evaluation to each reviewing Reliability Coordinator and each impacted Transmission Planner and RAS-entity. The PC is the functional entity best-suited to perform this evaluation because they have a wide-area planning perspective.

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments

Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: Yes

Answer Comment: Dominion suggests clarifying in R4 that the evaluation is a technical evaluation as stated below:

Each Transmission Planner shall perform a **technical** evaluation (planning analyses) evaluation of each RAS within its planning area at least once every 60-full-calendar-months and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies.

Response: Thank you for your comment.

The drafting team declines to make the suggested change.

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Selected Answer: No

Answer Comment: R4 should be modified to include a new part 4.5 that would require the Transmission Planner to identify any performance deficiencies in the RAS as well as alternatives for mitigating or correcting such deficiencies. The RAS-owners would not have the capability to identify alternatives for correcting deficiencies.

Response: Thank you for your comment.

The drafting team revised the requirement to make the Planning Coordinator (PC) the responsible entity for performing the periodic evaluations and requiring the PC to provide the results of the RAS evaluation to each reviewing Reliability Coordinator and each impacted Transmission Planner and RAS-entity.

Requirements R6 mandates the RAS-entity develop a Corrective Action Plan. If the RAS-entity needs assistance, it can engage its Transmission Planner or Planning Coordinator. The drafting team declines to make your suggested change.

Likes: 4

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5

Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Selected Answer: No

Answer Comment: It would be more appropriate to specify the RAS-entity in R4 instead of the RAS-owner.

The RAS-entity and the RAS-owner should be provided with the results of the review. The PC may be more appropriately qualified to review certain RAS than the TP. Consider revising R4 to read “Each Transmission Planner shall evaluate…”

Add wording to the Rationale for Requirement R4 to clarify that the intent is not to evaluate all RAS at the same time, but that each RAS is to be evaluated on a 60 full calendar month cycle.

Would the Planning Coordinator ever perform this evaluation instead of the Transmission Planner?

Response: Thank you for your comment.

The drafting team revised the requirement. The Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4 and is required to provide the results of the RAS evaluation to each reviewing Reliability Coordinator and each impacted Transmission Planner and RAS-entity. The PC is the functional entity best-suited to perform this evaluation because they have a wide-area planning perspective. Please see the complementary revisions to the Rationale boxes and Supplemental Material section of the draft standard.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:	No
Answer Comment:	ERCOT supports the comments submitted by the ISO/RTO Council.

Response: Please see the drafting team's responses to the referenced comments.

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:	No
Answer Comment:	PJM supports the comments submitted by the ISO/RTO Council.

Response: Please see the drafting team's responses to the referenced comments.

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer:	No
Answer Comment:	How would a scenario be addressed in which a RAS spans two or more Transmission Planner areas?

Response: Thank you for your comment.

The drafting team revised the requirement to make the Planning Coordinator (PC) the responsible entity for performing the periodic evaluations. The drafting team notes that the existing wording of the requirement allows the individual PCs to perform the evaluation of RAS within its own planning area, and also allows coordination of all relevant PCs to perform a joint evaluation of RAS that span multiple PC areas. The PC is the functional entity best suited to perform this evaluation because they have a wide-area planning perspective.

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer:	No
Answer Comment:	TANC has concerns with the current language in R4 because appears to assume that a RAS exists within a single planning area. NERC has not defined the term “planning area”, which creates ambiguity in the requirement’s language that states “Each Transmission Planner shall perform an evaluation of each RAS within its planning area.” This ambiguity is further compounded in circumstances where a single RAS exists within the footprints of multiple Transmission Planners (and

	Planning Coordinators). In such cases, it is unclear which Transmission Planners associated with the multiple RAS-owners for a single RAS would have responsibility in accordance with this standard.

Response: Thank you for your comment.

The drafting team revised the requirement to make the Planning Coordinator (PC) the responsible entity for performing the periodic evaluations. The drafting team notes that the existing wording of the requirement allows the individual PCs to perform the evaluation of RAS within its own planning area, and also allows coordination of all relevant PCs to perform a joint evaluation of RAS that span multiple PC areas.

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:	No
Answer Comment:	We generally agree with the process outlined by R4, but reiterate our comment that the Planning Coordinator, NOT the TP, should the entity responsible for this requirement. Many Transmission Owner organizations also perform the transmission planning function and as such, are also registered as the Transmission Planners (for the assets that they own). A proper and unbiased evaluation of the RAS performance should be conducted by an entity that is not in the same organization as the TO and has a wider perspective than the TO and TP. And since the RAS intended function its operational impact may affect more than one TOs and TPs, a PC is the

	most appropriate entity to perform this task than the TP, both from an independence and a wide area perspectives. We therefore suggest replacing the TP with the PC. This proposal is consistent with the basis for assigning R2 to the RC rather than the TOP. The RAS-entity and the RAS-owner should be provided with the result of the review. The PC may be more appropriately qualified to review certain RAS than the TP.

Response: Thank you for your comment.

The drafting team revised the requirement. The Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4 and is required to provide the results of the RAS evaluation to each reviewing Reliability Coordinator and each impacted Transmission Planner and RAS-entity. The PC is the functional entity best-suited to perform this evaluation because they have a wide-area planning perspective.

Richard Vine - California ISO - 2 -

Selected Answer:	No
Answer Comment:	The California ISO supports the comments of the ISO/RTO Standards Review Committee

Response: Please see the drafting team's responses to the referenced comments.

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Dixie Wells - Lower Colorado River Authority - 5 -

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Selected Answer: No

Answer Comment: To address existing entity NERC registration in the ERCOT region, "Transmission Planner" should be replaced with "Transmission Planner (in the ERCOT Region this applies to the Planning Authority and /or

Reliability Coordinator.)”

R4. Each Transmission Planner (in the ERCOT Region this applies to the Planning Authority and /or Reliability Coordinator) shall perform an evaluation of each RAS within its planning area at least once every 60-full-calendar-months and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Response: Thank you for your comment.

The drafting team revised the requirement. The Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4 and is required to provide the results of the RAS evaluation to each reviewing Reliability Coordinator and each impacted Transmission Planner and RAS-entity. The PC is the functional entity best-suited to perform this evaluation because they have a wide-area planning perspective.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	**Entity**	**Region**	**Segments**
Shannon Mickens	Southwest Power Pool Inc.	SPP	2

Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Selected Answer: Yes

Answer Comment: We feel that the Transmission Planner also conducting an analysis will help address changes to the RAS which could impact the BES. Additionally, we like the fact that the analysis can be performed earlier if changes to the systems topology or system operating conditions has a potential impact on the BES (as mentioned in the second paragraph of the Rationale Box for Requirement R4).

Response: Thank you for your comments.

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer:	Yes
Jeff Wells - Grand River Dam Authority - 3 -	
Selected Answer:	Yes
Rachel Coyne - Texas Reliability Entity, Inc. - 10 -	
Selected Answer:	No
Answer Comment:	Texas RE asks the drafting team to consider adding the Planning Coordinator to Requirement R4 for instances where a RAS covers multiple Transmission Planner areas. The current practice the ERCOT region is ERCOT conducts the 5-year review of each RAS; however, ERCOT is the Planning Coordinator, not a Transmission Planner. Texas RE asks the drafting about the term “60-full-calendar-months” in Requirements R4 and R6. The term is not defined and is not consistent with other standards and requirements. PRC-006 indicates five years, PRC-010-1 indicates 60 calendar months, and PRC-014 indicates five years. Texas RE recommends not introducing new terms and to be as consistent as possible. Is the SDT defining a “full calendar month” or

"calendar year"? The RSAW is not the place to define a new term and the definition is different than terms used in PRC-005. This definition is misleading to those reviewing the document and could potentially exacerbate reliability issues nearly seven years based on the "definition" provided in the Note to Auditor section of R4 in the RSAW.

The intent of Requirement R9 should be to update once per year not once per 729 days (2 years minus 1 day) which would be allowable by the definition of full calendar year as stated in the RSAW.

Texas RE recommends defining the term "planning area". It should be prescriptive enough to include GOs and DPs that are RAS-owners, i.e. generator owners or distribution providers that own all or part of a RAS. In Requirement R4, by default a Generator Owner or Distribution Provider owned RAS would be within a Transmission Planners planning area, correct? Please confirm or give specifics as to why a GO or DP owned RAS would not be within a Transmission Planners planning area.

Response: Thank you for your comment.

The drafting team revised the requirement. The Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4 and is required to provide the results of the RAS evaluation to each reviewing Reliability Coordinator and each impacted Transmission Planner and RAS-entity. The PC is the functional entity best-suited to perform this evaluation because they have a wide-area planning perspective.

The drafting team uses the clarifier "full" to be clear that partial months are not counted. For example, if the starting point is in the middle of a calendar month, the entity will have until the end of the last month of the stated period.

The drafting team revised the language to "at least once every 12-full calendar months".

The drafting team maintains that the term “planning area” is generally understood throughout the industry and declines to attempt to define it in this standard.

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Selected Answer:	No
Answer Comment:	The RAS owner must review the RASs in R4, R5, R6. Nowhere does it give the reviewing Reliability Coordinator the authority to dispute the evaluation in R4, dispute the analysis in R5, and require changes to the corrective action plan in R6. RC is just provided the results of analysis but is not given any authority to do anything with them.

Response: Thank you for your comment.

The drafting team agrees that the Reliability Coordinator is provided the results of the requirements you mention and the drafting team maintains that is sufficient. The Reliability Coordinator is already responsible for the reliability of its RC Area and has the authority to address any reliability concern through other standards.

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:	No

Answer Comment: Although Hydro One Networks Inc. agrees with the evaluation process, we emphasize (as described above in Q1) that the evaluation of each new RAS must also be required from the TP or PC before the RAS is approved and implemented by the RAS owner/entity. We recognize that it is inconsistent to require the initial assessment of a RAS from a RAS owner/entity (in R1), and the subsequent/periodic assessments from a TP (in R4).

Response: Thank you for your comment.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the “flexibility” to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer: Yes

Answer Comment: Recommend changing 60 full calendar months to 5 calendar years, to allow the RAS evaluation to fit within the annual Planning Assessment process which may vary from year to year.

Response: Thank you for your comment.

The drafting team based the 60 full calendar months schedule on the existing PRC-014-0, Requirement R1 to perform an assessment “at least once every five year. . .” The drafting team does not see a convincing reliability reason to further extend this schedule and declines to make the suggested change.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5

John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Selected Answer: No

Answer Comment:

(1) We believe 60 calendar months is an appropriate amount of time to conduct RAS periodic evaluations. However, we do not believe the TP has sufficient visibility outside of its area to determine if the BES will remain stable or the occurrence of a Cascading outage will be minimized following the inadvertent operation of a RAS from any single RAS component malfunction. These "wide-area" views are only available to the PC. We believe the requirement should be rewritten to include the PC as an applicable entity for these technical evaluations.

(2) We have concerns that the requirement does not identify what events will trigger when the clock begins on the 60 calendar month timeframe. We ask the SDT to clarify when the clock starts for these periodic evaluations – is it after the initial installation, after the latest modification to RAS functionality, or following a response to a CAP?

Response: Thank you for your comments.

Based on comments, the drafting team revised the requirement. The Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4 and is required to provide the results of the RAS evaluation to each reviewing Reliability Coordinator and each impacted Transmission Planner and RAS-entity. The PC is the functional entity best-suited to perform this evaluation because they have a wide-area planning perspective.

For existing RAS, the initial performance of the requirement must be completed within 60 full calendar months of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within sixty full calendar months of the RAS approval date by the reviewing RC(s). The drafting team added language to the Implementation Plan to provide additional clarity.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

3. RAS Inadvertent Operation: Do you agree with Requirement 4 Part 4.3 and Attachment 1 which stipulates that RAS inadvertent operation due to a single component malfunction still satisfies the System performance requirements common to TPL-001-4 P1-P7 events listed in Parts 4.3.1-4.3.5? (Note that this requirement remains the same as PRC-012-0 R1.4 except for the allowance for designed-in security that would prevent RAS inadvertent operation for any single component malfunction). If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:	Yes

Thomas Foltz - AEP - 5 -

Selected Answer:	No
Answer Comment:	Clarity is needed in R4 as to exactly what the trigger is for the 60-full-calendar-months periodic review. Is it tied, perhaps, to the in-service status? In addition, rather than a 60 full month periodic review, AEP suggests a “5 calendar year” review. This would allow flexibility for an entity to integrate this work into its annual planning cycle.

Response: Thank you for your comment.

The initial performance of the evaluation must be completed within 60 full calendar months of the effective date of PRC-012-2. The successive performances are triggered by the previous evaluation date. The drafting team added language to the Implementation Plan, rationale box, and Supplemental Material section of the standard to provide additional clarity. The drafting team does not see any benefit in your suggestion and declines to make the change.

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6

Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: Yes

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Selected Answer: No

Answer Comment: Needs further clarification. The Transmission Planner or the group that *owns* the RAS should be responsible for the evaluation, coordination and testing of the RAS.

Response: Thank you for your comment.

The drafting team revised the requirement and the Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4. The drafting team agrees that the RAS-entity may need to be contacted by the PC. The PC is the functional entity best suited to perform this evaluation because they have a wide-area planning perspective.

Chris Scanlon - Exelon - 1 -

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Selected Answer: Yes

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer:	Yes

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer:	Yes

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer:	Yes

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:	No

Answer Comment:	Recommend deleting Part 4.3 since we find it hard to conceive how the inadvertent operation of RAS can result in unacceptable system performance when the primary motivation for installing any RAS is to achieve acceptable system performance. We acknowledge that inadvertent RAS operation is undesirable, but we also recognize that it is fundamentally the same as a RAS misoperation. And therefore, any adverse reliability impact due to inadvertent RAS operation would get addressed in R5 during RAS operational performance analysis. Consequently, we do not see any reliability risk, and thus no associated compelling need, to identify the potentially unacceptable system performance based on simulations/analyses performed for periodic RAS evaluation using models that reflect "typical" rather than actual operating conditions. Although we agree with the goal of a robust RAS design that is not susceptible to RAS misoperation caused by the malfunction of a single component, we also believe this objective is effectively accomplished by any corrective action plan spawned by the RAS operational performance analysis in R5.

Response: Thank you for your comment.

The drafting team maintains that it is desirable from a reliability perspective to identify potential inadvertent operation issues in Requirement R4 rather than waiting for an incorrect operation to occur to determine whether actual System performance was unacceptable. RAS operation when applicable system conditions are not present may degrade system performance or pose a risk to reliability. For example, a RAS designed to shed a certain amount of load following a loss of generation can lead to overfrequency on the System or other issues if the load is shed without the loss of generation actually occurring. The drafting team maintains it is better to be proactive rather than reactive from a reliability perspective and declines to make the suggested change.

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment: Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Response: Please see the drafting team's responses to the referenced comments.

David Greene - SERC - 1,10 - SERC

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Selected Answer: Yes

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: No

Answer Comment: Part 4.3 addresses inadvertent operation and addresses security of the RAS. This is important however and we suggest that only 4.3.1 and 4.3.2 as well as controlling system separation are the only aspects that are needed. In Attachment 2 we agree that inadvertent operation needs to be understood however if that inadvertent operation does not cause one of the three significant adverse impacts to the reliability of the BES then the RAS should not be subject to additional requirements which likely will only have a localized effect. The addition of this language in R 4.3.3, 4.3.4, and 4.3.5 unnecessarily may result in local RAS to have increased design complexity, additional components which may increase the likelihood of misoperation (decreasing the reliability of the RAS) and excessive costs. We suggest the SDT consider that all RAS which have a wider impact, whose inadvertent operation could result in Cascading, System Separation or instability be subject to this standard and its design requirements. To place these requirements as written on all RAS would be of little or no benefit to achieving an adequate level of reliability on the BES and based on this we would characterize this as placing a requirement such as those removed by Paragraph 81 in the standard. Furthermore, this could actually be a detriment to the reliable operation of a local RAS subjecting it to unnecessary additional design requirements.

Response: Thank you for your comment.

The drafting team included a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process.

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment: Consider adding 4.3.6 "Frequency Trigger Limits (FTLs) shall be within acceptable limits as established"

Response: Thank you for your comment.

The drafting team contends that frequency trigger limits are only relevant in Reliability Standard BAL-001-2 and declines to make the suggested change.

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Selected Answer: No

Answer Comment: Part 4.3 addresses inadvertent operation and addresses security of the RAS. This is important; however, we suggest that 4.3.1, 4.3.2, and controlling system separation should be the only aspects that are needed. We do not understand the intent of 4.3.3 “applicable facility ratings.” Is this normal, emergency, DAL (drastic action limit), etc.? In Attachment 2, we agree that inadvertent operation needs to be understood however if that inadvertent operation does not cause one of the three significant adverse impacts to the reliability of the BES, then the RAS should not be subject to additional requirements when the inadvertent operation likely will only have a localized effect. The addition of this unnecessary language in R 4.3.3, 4.3.4, and 4.3.5 may result in local RAS having increased design complexity, additional components that may increase the likelihood of misoperation (decreasing the reliability of the RAS) and excessive costs. We suggest the SDT consider that all RAS that have a wider impact, whose inadvertent operation could result in Cascading, System Separation, or instability, be subject to this standard and its design requirements. To place these requirements as written on all RAS would be of little or no benefit to achieving an adequate level of reliability on the BES and based on this we would characterize this as a Paragraph 81 requirement in the standard. Furthermore, this could actually be a detriment to the reliable operation of a local RAS, subjecting it to unnecessary additional design requirements.

Response: Thank you for your comment.

The drafting team included a provision that RAS can be designated as “limited impact” if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Selected Answer: Yes

Mike Smith - Manitoba Hydro - 1 - **Selected Answer:** Yes
Erika Doot - U.S. Bureau of Reclamation - 5 - **Selected Answer:** Yes
Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 - **Selected Answer:** Yes
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - **Group Name:** IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Selected Answer: Yes

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment: See comment in no. 7.

Response: Please see the drafting team's response to the referenced comment.

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment: Part 4.3 addresses inadvertent operation and addresses security of the RAS. This is important however we suggest that only 4.3.1 and 4.3.2 as well as controlling system separation are the only aspects that are needed. We do not understand the intent of 4.3.3 “applicable facility ratings”. Is this normal, emergency, DAL (drastic action limit), etc.? In Attachment 2 we agree that inadvertent operation needs to be understood however if that inadvertent operation does not cause one of the three significant adverse impacts to the reliability of the BES then the RAS should not be subject to additional requirements which likely will only have a localized effect. The addition of this language in R 4.3.3, 4.3.4, and 4.3.5 unnecessarily may result in local RAS to have increased design complexity, additional components which may increase the likelihood of misoperation (decreasing the reliability of the RAS) and excessive costs. We suggest the SDT consider that all RAS which have a wider impact, whose inadvertent operation could result in Cascading, System Separation or instability be subject to this standard and its design requirements. To place these requirements as written on all RAS would be of little or no benefit to achieving an adequate level of reliability on the BES and based on this we would characterize this as placing a Paragraph 81 requirement in the standard. Furthermore, this could actually be a detriment to the reliable operation of a local RAS subjecting it to unnecessary additional design requirements.

Response: Thank you for your comment.

The drafting team included a provision that RAS can be designated as “limited impact” if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process.

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: No

Answer Comment: Dominion concurs with the idea of an inadvertent operations test; however R4.3.5 transient voltage response should not be part of that test. Preventing FIDVR is only necessary to prevent cascading due to motor stalling (an unlikely outcome) which is addressed under R4.3.2. Dominion believes that slow transient voltage response that does not lead to cascading and is a customer power quality issue and not a reliability issue.

Response: Thank you for your comment.

The drafting team disagrees with your comment. Requirement R4, Part 4.1.3.5 regarding transient voltage response is a performance requirement common to other TPL contingencies (P1 to P7), and does not apply only to FIDVR phenomena but any type of transient behavior that may affect stability.

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1

Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Answer Comment: No comment.

Likes: 4

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segment
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3

Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1

Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1

Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Selected Answer: No

Answer Comment: Part 4.3 addresses inadvertent operation and addresses security of the RAS. This is important. However, we suggest that only sub-Parts 4.3.1 and 4.3.2 as well as controlling system separation are the only aspects that are needed. We do not understand the intent of sub-Part 4.3.3 “applicable facility ratings”. Is this normal, emergency, DAL (drastic action limit), etc.? In Attachment 2 we agree that inadvertent operation needs to be understood. However, if that inadvertent operation does not cause one of the three significant adverse impacts to the reliability of the BES then the RAS should not be subject to additional requirements which likely will only have a localized effect. The addition of this language in sub-Parts 4.3.3, 4.3.4, and 4.3.5 unnecessarily may result in local RAS to have increased design complexity, additional components which may increase the likelihood of misoperation (decreasing the reliability of the RAS) and excessive costs. We suggest the SDT consider that all RAS that have a wider impact, those whose inadvertent operation could result in Cascading, System Separation or instability be subject to this standard and its design requirements. To place these requirements as written on all RAS would be of little or no benefit to achieving an adequate level of reliability on the BES, and based on this we would characterize this as placing a Paragraph 81 requirement in the standard. Furthermore, this could actually be a detriment to the reliable operation of a local RAS subjecting it to unnecessary additional design requirements.

Response: Thank you for your comment.

The drafting team included a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment: ERCOT supports the comments submitted by the ISO/RTO Council.

Response: Please see the drafting team's responses to the referenced comments.

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:	Yes

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer:	Yes

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:	No
Answer Comment:	At the present time there are RAS in service that have a limited local impact. To universally apply the same design criteria to all RAS regardless of their impact on BES in case of an inadvertent operation may have no cost benefit in the case of the RAS installed to address local problems.

We propose the following to be included in the standard:

An inadvertent operation in the RAS, when the RAS is intended to operate, does not result in any of the following conditions on the BES:

1. Cascading

2. Uncontrolled System Separation

3. Instability

When the criteria mentioned above is not met a secure design will be required.

Response: Thank you for your comment.

The drafting team included a provision that RAS can be designated as “limited impact” if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process.

Richard Vine - California ISO - 2 -

Selected Answer: Yes

Answer Comment: The California ISO supports the comments of the ISO/RTO Standards Review Committee

Response: Please see the drafting team's responses to the referenced comments.

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Dixie Wells - Lower Colorado River Authority - 5 -

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Selected Answer: Yes

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Selected Answer: Yes

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer:	Yes

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer:	Yes

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:	Yes
Answer Comment:	The SDT may want to consider adding "Applicable System Operating Limits shall not be exceeded" as a sub-bullet to Requirement R4.3.

Response: Thank you for your comment.

The drafting team maintains that the Parts 4.1.3.1-4.1.3.5 are aligned with similar TPL performance requirements for contingencies P0-P7 as well as SOLs calculated for both the planning and operating horizons. The drafting team declines to make the suggested change.

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Selected Answer: Yes

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3

Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer: No

Answer Comment: FMPA agrees with the intent of R4.3 – that construction of devices/systems as an integral part of the BES should be held to same standards as construction of physical facilities. However, we believe there is a problem with the wording of the first sentence. It is possible to read the first sentence to be requiring that inadvertent operation of the RAS due to a single component malfunction be studied as a planning event regardless of whether the system is designed to prevent such an event from occurring. FMPA believes the intent of the language is that items 4.3.1 through 4.3.5 only apply if single component malfunction does actually produce an operation of the RAS. If this were not true (e.g. if the language in R4.3 was requiring the study of the inadvertent RAS operation against the criteria in 4.3.1 through 4.3.5 regardless of whether a single component malfunction could actually cause the RAS to operate), the language would essentially be requiring that TPL-001-4 Planning Event criteria be applied to what amounts to an Extreme Event. This is partly because of the use of the term "malfunction" as opposed to "failure". This is not consistent with TPL-001-4 which refers to protection system "failures". This is an important distinction because typically protection systems are designed such that if a component fails, it does so without issuing a false trip. A malfunction can be interpreted to mean a large number of absurdly unlikely things which are over and above the level of rigor required by TPL-001-4. FMPA understands that the SDT desired to consider the use of non-“protection system” control devices using this standard, but the language as written does not allow those entities that are using protective devices to take credit for basic design principles such as redundancy. Suggest either expressly allowing entities to take credit for redundancy, switching to using the term “failure” or both.

Response: Thank you for your comment.

The drafting team agrees with the intent of the comment - that 4.1.3.1-4.1.3.5 only apply if a single component malfunction, per the design of the RAS, can produce an inadvertent operation of the RAS (or part of the RAS). The drafting team maintains that there are other modes of improper component operation that the term “failures” may not clearly address, and therefore “malfunction” is a more appropriate term. Requirement R4, Part R4.1.3 maintains consistency with existing PRC-012-1 Requirement R1, R1.4 regarding inadvertent operation but is meant to clarify that design considerations to improve security can be implemented that will essentially prevent inadvertent operation. If single component malfunction (or failure) cannot cause an inadvertent operation, 4.1.3.1-4.1.3.5 do not need to be assessed.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name:	ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Selected Answer: No

Answer Comment: Certain aspects of the TPL-001-4 P1-P7 events identify actions under a steady state or a stability assessment. We have concerns that applicable Facility Rating exceedances and BES voltages deviations, as identified with TPL-001-4, are only applicable under steady state conditions. We recommend the SDT modify Requirement R4 to identify these references within the context of a steady state assessment, instead of a transient state, to align with existing NERC standards.

Response: Thank you for your comment.

The drafting team agrees that applicable Facility Rating and BES voltage deviations, as identified with TPL-001-4 are applicable under steady-state conditions rather than transient conditions. However, for the purpose of the evaluation required in Requirement R4, Part 4.1.3 (Parts 4.1.3.1-4.1.3.5), RAS inadvertent operation needs to be assessed with regards to both the transient stability and steady-state performance requirements of TPL-001-4 P1-P7 (as for any TPL contingency). The drafting team declines to make the suggested change.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

4. RAS Single Component Failure: Do you agree with Requirement 4 Part 4.4 and Attachment 1 which stipulates that any RAS intended to satisfy System performance requirements in a TPL standard must still satisfy those requirements when experiencing a single component failure? (Note that this requirement remains unchanged from PRC-012-0 R1.3.) If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5

Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: No

Answer Comment: The NSRF recommends two modifications to Part 4.4.:

One modification is to explicitly include "option c" in the Implementation section of the Supplemental Material associated with the Standard. The revised wording could be, "A single component failure in RAS, when the RAS is intended to operate, or alternative automatic actions back up the failures of single RAS components . . .” Including text about the alternative option in the standard, rather than the Supplemental Material would assure that it cannot be dismissed by an auditor.

The other modification is to remove the unnecessary linking of R4.4 to TPL-001-4 performance requirements with linking to the performance requirements already expressed in R4.3 of PRC-002-2. The revised wording could be, “. . . satisfies the same performance criteria given in Part 4.3”. This change makes the performance requirements of Part 4.3 and Part 4.4 consistent with each other and subject to changes in the PRC-012-2, rather than independent changes in another NERC standard.

Response: Thank you for your comments.

The drafting team maintains that the alternative automatic actions described in the Attachment 1 (Supplemental Material) are examples of how the standard requirement can be met. The standard is not prescriptive in dictating the “how” to achieve the reliability objectives. The language of Requirement 4, Part 4.1.4 does not preclude any of the options ‘a’ through ‘d’ from being applied. As long as the relevant TPL standard performance requirements are satisfied, Part 4.1.4 is met. The drafting team declines to make the suggested change.

The intent of Requirement 4, Part 4.1.4 is to ensure the RAS satisfies all of the performance requirements specified in the TPL standard (which are more than those listed in Part 4.1.3) with regards to single component failure. Furthermore, the drafting team contends that the reference to the TPL standard is necessary to differentiate between RAS installed for meeting planning event performance requirements and those installed for extreme events. The drafting team declines to make the suggested change.

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Selected Answer: Yes

Chris Scanlon - Exelon - 1 -

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Selected Answer: Yes

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Selected Answer:	Yes
Jeri Freimuth - APS - Arizona Public Service Co. - 3 -	
Selected Answer:	Yes
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP	
Selected Answer:	No
Answer Comment:	We do not agree that the "single component failure" requirement should apply to **all** RAS installed to satisfy TPL performance requirements, by completely disregarding the severity of adverse system impact resulting from the RAS failure to operate. In other words, we are advocating that due regard be given to the RAS classifications/types existing in NPCC, WECC and TRE regions, as well as the recommended RAS/SPS classifications in the SAMS-SPCS white paper. Using the RAS nomenclature proposed in the white paper,

we recommend that the "single component failure" requirement be limited to Type PS (Planning Significant) schemes only. Excluding the Type PL schemes, like the accepted exclusion for "safety net" (Type ES/EL) schemes, does not necessarily compromise Adequate Level of Reliability in the BES. We recognize that this approach will require judicious selection of the demarcation criteria between Significant (Wide Area) versus Limited (Local) schemes – however, the existing NPCC and/or WECC demarcation criteria may serve as a reasonably good starting point. Lastly, we disagree with the claim that Part 4.4 remains unchanged from the existing R1.3 in PRC-012-0 – although both may have essentially the same verbiage, the context and the scope of applicability are widely different. While the existing R1.3 may be rightly interpreted to allow discretion to the RRO to determine which RAS/SPS "Types" must be subject to the more robust design that is not degraded by "single component failure", Part 4.4 takes away that discretion by virtue of being a continent-wide standard. There is no factual evidence to suggest that the failure-to-operate of any Local/Limited RAS has resulted in unacceptable/adverse BES performance to warrant "raising the bar" on applicability of "single component failure" requirement.

Response: Thank you for your comment.

The drafting team included a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process.

Molly Devine - IDACORP - Idaho Power Company - 1 - **Selected Answer:** Yes
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC **Selected Answer:** Yes
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC **Selected Answer:** No **Answer Comment:** Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports. **Response:** Please see the drafting team’s responses to the referenced comments.

David Greene - SERC - 1,10 - SERC

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Selected Answer: Yes

Answer Comment:

Suggest adding clarity to indicate the intent of R4 is not to evaluate the performance of the RAS “following” an inadvertent operation since this is covered by R5. The below statement from the rationale for R4 can be misinterpreted to imply R4 requires the Transmission Planner to perform a technical evaluation “following” an inadvertent operation.

Copied from Rationale for R4:
The purpose of a periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that requirements for BES performance following an inadvertent RAS operation or a single component failure in the RAS continues to be satisfied.

Response: Thank you for your comment.

The drafting team agrees and revised the Requirement R4 rationale sentence as follows: "The purpose of a periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that, if a RAS single component failure or single component malfunction were to occur, requirements for BES performance would continue to be satisfied."

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:	No
Answer Comment:	ATC recommends two modifications to Part 4.4. One modification is to explicitly include "option c" in the Implementation section of the Supplemental Material associated with the Standard. The revised wording could be, "A single component failure in RAS, when the RAS is intended to operate, or alternative automatic actions back up the failures of single RAS components . . ." Including text about the alternative option in the standard, rather than the Supplemental Material would assure that it cannot be dismissed by an auditor. The other modification is to remove the unnecessary linking of R4.4 to TPL-001-4 performance requirements with linking to the performance requirements already expressed in R4.3 of PRC-002-2. The revised wording could be, ". . . satisfies the same performance criteria given in Part 4.3". This

	change makes the performance requirements of Part 4.3 and Part 4.4 consistent with each other and subject to changes in the PRC-012-2, rather than independent changes in another NERC standard.

Response: Thank you for your comments.

The drafting team maintains that alternative automatic actions described in the Attachment 1 supplemental material are examples of how the standard requirement can be met. The standard is not prescriptive in dictating the "how" to achieve the reliability results. The language of Requirement 4, Part 4.4 does not preclude any of the options 'a' through 'd' from being applied. As long as the relevant TPL standard performance requirements are satisfied, Part 4.4 is met. The drafting team declines to make the suggested change.

The intent of Requirement 4, Part 4.4 is to ensure the RAS satisfies all of the performance requirements specified in the TPL standard, which are more than those listed in Part 4.3, with regards to single component failure. The drafting team also contends that the reference to the TPL standard is necessary to differentiate between RAS installed for meeting planning event performance requirements and those installed for extreme events. The drafting team declines to make the suggested change.

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer:	No
Answer Comment:	Requirement R4 Part 4.4 is problematic for a number of reasons. First, placing this requirement on the Transmission Planner does not conform to the responsibilities or abilities of the Transmission Planner. While the TP may have some familiarity with the design of the RAS or with the Operating

	Procedures which may be in place, it does not know or need to know the specifics of a single component failure, just the ramification of an overall RAS operation failure or inadvertent operation. Currently, the unapproved standard PRC-012-0 and -1 R1.3 contains a single component failure design requirement which is currently unapproved by FERC and the applicable governmental authorities in Canada. When these standards were approved by the NERC BOT there was no NERC BES definition nor was there an approved definition of what a RAS is. We believe that had the full implication of the costs to be borne by the industry been recognized and subsequent minimal or no reliability benefit associated with meeting that requirement for local impact only schemes, the standard would not have been approved. Further, the System Protection Coordination Subcommittee of NERC had specifically noted and suggested that 4 types of RAS are on the BES. Two of these were local and these categories were developed to afford the SDT to tailor specific and appropriate reliability and security requirements on these local type schemes. To broadly apply these more stringent requirements to all RAS on the new BES with the new RAS definition has little cost benefit. In addition, the existing PRC-012-0 and -1 only require a single component failure review and design requirement at the time of review. PRC-014-0 and -1, which are the SPS/RAS assessment standards currently do not require the Transmission Planner to include a requirement such as Requirement R4 Part 4.4 in their periodic assessment. The regions should each have a process for ensuring the reliability of the BES and that the necessary level of reliability and security had been met at the time of approval. Furthermore, misoperations studies have not indicated that there is a reliability need to incorporate single component failure design into local systems. These local RAS which do not meet the requirement would need to be redesigned, outages taken and then have their revisions made to come into compliance. This, in and of itself would represent a risk to the

operation and reliability of the BES.

Requirement R4 Part 4.4 currently states;

"4.4 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 is designed."

We suggest Part 4.4 be removed. However, if the SDT is unwilling to remove it we would propose the following:

4.4 A single component failure in the RAS, when the RAS is intended to operate,

does not result in any of the following conditions on the BES:

- Cascading
- Uncontrolled System Separation
- Instability

The above modification would provide the necessary level of security and reliability to the BES. Ensuring that RAS installed on the BES or to meet TPL requirements would only be required when the RAS operation is critical and any inadvertent operation results in a significant impact to the BES.

Response: Thank you for your comments.

The drafting team revised Requirement 4 to make the Planning Coordinator (PC) the responsible entity. The drafting team maintains that the PC does not need to know the detailed RAS design and can consult with the RAS-entity to ascertain the consequences of any single component failure. The drafting team maintains that the PC is the proper entity to perform the System performance evaluations listed in Requirement 4, Parts 4.1 through 4.4. The revisions to Requirement 4, Part 4.4 have effectively limited the number of RAS to be evaluated for single component failure and the amount of associated data the PC will need to obtain to perform the evaluation.

The drafting team agrees in principle with your comment and has revised Requirement 4, Part 4.4 to allow the Reliability Coordinator to determine whether a RAS has a "limited impact" and can therefore be exempted from Part 4.4 of the requirement. The drafting team also added an explanatory footnote and revised Attachments 1 and 2 to reflect the change in Part 4.4.

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment: Please affirm this understanding: For single component failure, a RAS must still satisfy System performance requirements.

Response: Thank you for your comments.

The drafting team agrees with your comment. Please see the revised Requirement 4, Part 4.4 which no longer applies to limited impact RAS.

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Selected Answer:	No
Answer Comment:	Requirement R4 Part 4.4 is problematic for a number of reasons. First, placing this requirement on the Transmission Planner does not conform to the responsibilities or abilities of the Transmission Planner. While the TP may have some familiarity with the design of the RAS or with the Operating Procedures in place, they do not know or need to know the specifics of a single component failure. The TP just needs to know the ramifications of an overall RAS operation failure or inadvertent operation. Currently, standards PRC-012-0 and PRC-012-1 R1.3 contain a single component failure design requirement. When these standards were approved by the NERC BOT, there was no NERC BES definition nor was there an approved definition of a RAS. We believe that had the full implication of the costs to be borne by the industry and the subsequent minimal or no reliability benefit associated with this (local impact only schemes) had been recognized, the standard would not have been approved by the NERC BOT. Further, the System Protection Coordination Subcommittee of NERC had specifically noted and suggested that 4 types of RAS are on the BES. Two of these types were local and these categories were developed to allow the SDT to tailor specific and appropriate reliability and security requirements on these local type schemes. To broadly apply these more stringent requirements to all RAS on the new BES with the new RAS definition has no cost benefit. In addition, PRC-012-0 and PRC-012-1 only require a single component failure review and design requirement at the time of review. PRC-014-0 and PRC-014-1, which are the SPS/RAS assessment standards, currently do not require the Transmission Planner to include a

requirement such as Requirement R4 Part 4.4 in their periodic assessment. The SDT has gone, in our view, unnecessarily beyond the intent of the current standards in this regard.

In addition, it should be noted that all existing RAS have gone through regional reviews and been approved for implementation. These existing RAS may not have met the existing single component failure requirement due to the revision of the BES. The regions each have a process for ensuring the reliability of the BES and the necessary level of reliability and security has been met at the time of approval. Furthermore, misoperations studies have not indicated that there is a reliability need to incorporate single component failure design into local systems. These local RAS, which do not meet the requirement, would need to be redesigned, undergo outages, and then have revisions made to bring them into compliance. This, in and of itself would represent a risk to the operation and reliability of the BES.

Requirement R4 Part 4.4 currently states:

"4.4 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 is designed."

We suggest Part 4.4 be removed. However, if the SDT is unwilling to remove it, we propose the following:

"4.4 A single component failure in the RAS, when the RAS is intended to operate, does not result in any of the following conditions on the BES:

- Cascading

- Uncontrolled System Separation
- Instability"

The above modification would provide the necessary level of security and reliability to the BES. This ensures that RAS installed on the BES or installed to meet TPL requirements would only be required to meet Part 4.4 when the RAS operation is critical and any inadvertent operation results in a significant impact to the BES.

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

Response: Thank you for your comments.

Based on other comments, the drafting team revised Requirement 4 to make the Planning Coordinator (PC) the responsible entity. The drafting team maintains that the PC does not need to know the detailed RAS design and can consult with the RAS-entity to ascertain the consequences of any single component failure. The drafting team maintains that the PC is the proper entity to perform the System performance evaluations listed in Requirement 4, Parts 4.1 through 4.4. The revisions to Requirement 4, Part 4.4 have effectively limited the number of RAS to be evaluated for single component failure and the amount of associated data the PC will need to obtain to perform the evaluation.

The drafting team agrees in principle with your comment and has revised Requirement 4, Part 4.4 to allow the Reliability Coordinator to determine whether a RAS has a "limited impact" and can therefore be exempted from Part 4.4 of the requirement. The drafting team also added an explanatory footnote and revised Attachments 1 and 2 to reflect the change in Part 4.4.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Selected Answer: Yes

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Selected Answer:	Yes
Answer Comment:	
Oliver Burke - Entergy - Entergy Services, Inc. - 1 -	
Selected Answer:	Yes
Answer Comment:	See comment in no. 7.
Response:	
Mark Kenny - Eversource Energy - 3 -	
Selected Answer:	No
Answer Comment:	Requirement R4 Part 4.4 is problematic for a number of reasons. First, placing this requirement on the Transmission Planner does not conform to

the responsibilities or abilities of the Transmission Planner. The TP, although may have some familiarity with the design of the RAS or with the Operating Procedures which may be in place does not know or need to know the specifics of a single component failure, just the ramification of an overall RAS operation failure or inadvertent operation. Currently, the unapproved standard PRC-012-0 and -1 R1.3 contains a single component failure design requirement which is currently unapproved by FERC and the applicable governmental authorities in Canada. When these standards were approved there was no NERC BES definition nor was there an approved definition of what a RAS is. We believe that had the full implication of the costs to be borne by the industry been recognized and subsequent minimal or no reliability benefit associated with meeting that requirement for local impact only schemes, the standard would not have been approved. Further, the System Protection Coordination Subcommittee of NERC had specifically noted and suggested that 4 types of RAS are on the BES. Two of these were local and these categories were developed to afford the SDT to tailor specific and appropriate reliability and security requirements on these local type schemes. To broadly apply these more stringent requirements to all RAS on the new BES with the new RAS definition has no cost benefit. In addition, the existing PRC-012-0 and -1 only require a single component failure review and design requirement at the time of review. PRC-014-0 and -1, which are the SPS/RAS assessment standards currently do not require the Transmission Planner to include a requirement such as Requirement R4 Part 4.4 in their periodic assessment. The SDT has gone, in our view, unnecessarily beyond the intent of the current standards in this regard.

In addition it should be noted that all existing RAS have gone through regional reviews and been approved for implementation. These existing RAS may not have met the existing single component failure requirement due to the revision of the BES. The regions each have a process for ensuring the reliability of the BES and that the necessary level of reliability and security had been met at the time of approval. Furthermore, misoperations studies have not indicated that there is a reliability need to incorporate single component failure design into local systems. These local RAS which do not meet the requirement would need to be redesigned, outages taken and then have their revisions made to come into compliance. This, in and of itself would represent a risk to the operation and reliability of the BES.

Requirement R4 Part 4.4 currently states;

"4.4 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 is designed."

We suggest Part 4.4 be removed. However, if the SDT is unwilling to remove it we would propose the following:

4.4 A single component failure in the RAS, when the RAS is intended to operate,

does not result in any of the following conditions on the BES:

- Cascading
- Uncontrolled System Separation
- Instability

The above modification would provide the necessary level of security and reliability to the BES. Ensuring that RAS installed on the BES or to meet TPL requirements would only be required when the RAS operation is critical and any inadvertent operation results in a significant impact to the BES.

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

Response: Thank you for your comments.

The drafting team revised Requirement 4 to make the Planning Coordinator (PC) the responsible entity. The drafting team maintains that the PC does not need to know the detailed RAS design and can consult with the RAS-entity to ascertain the consequences of any single component failure. The drafting team maintains that the PC is the proper entity to perform the System performance evaluations listed in Requirement 4, Parts 4.1 through 4.4. The revisions to Requirement 4, Part 4.4 have effectively limited the number of RAS to be evaluated for single component failure and the amount of associated data the PC will need to obtain to perform the evaluation.

The drafting team agrees in principle with your comment and has revised Requirement 4, Part 4.4 to allow the Reliability Coordinator to determine whether a RAS has a “limited impact” and can therefore be exempted from Part 4.4 of the requirement. The drafting team also added an explanatory footnote and revised Attachments 1 and 2 to reflect the change in Part 4.4.

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: No

Answer Comment: Dominion believes that redundancy should not be required for a RAS designed for events such as TPL-001-4 P4 (stuck breaker) or P5 (relay failure event). The design should not have to consider two failures which is improbable. As an analogy, in places where there is no RAS scheme, there is no requirement to test a P4 stuck breaker event and then assume that the breaker failure relay does not work, essentially combining P4 and P5 together. Designing a redundant RAS for breaker failure could require installation of two breaker failure relays per breaker to initiate the RAS and maintain complete redundancy. This leads to excessive complexity which can hurt reliability.

Additionally, Dominion suggest adding clarity to indicate the intent of R4 is not to evaluate the performance of the RAS “following” an inadvertent operation since this is covered by R5. The rationale statement for R4 can be misinterpreted to imply R4 requires the Transmission Planner to perform a technical evaluation **“following”** an inadvertent operation.

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

Response: Thank you for your comments.

The SDT agrees that a single component failure of a RAS during a P4 or P5 event has a low probability of occurrence. However, the SDT maintains that the single component failure requirement applies to contingencies in TPL-003 in the current standard. Not having the single component failure test apply to P4 or P5 events would be lowering the bar from the previous standard.

The SDT agrees and has revised the R4 rationale sentence as follows: "The purpose of a periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that, if a RAS single component failure or single component malfunction were to occur, requirements for BES performance would continue to be satisfied."

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Answer Comment: No comment

Likes: 4

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable

Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6

Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1

Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Selected Answer: No

Answer Comment: Requirement R4 Part 4.4 is problematic for a number of reasons. First, placing this requirement on the Transmission Planner does not conform to the responsibilities or abilities of the Transmission Planner. The TP may have some familiarity with the design of the RAS or with the Operating Procedures which may be in place, but does not know or need to know the specifics of a single component failure, just the ramification of an overall RAS operation failure or inadvertent operation. Currently, Part R1.3 of standards PRC-012-0 and -1 contains a single component failure design requirement. When these standards were approved by the NERC BOT there was no NERC BES definition nor was there an approved definition of what a RAS is. We believe that had the full implication of the costs to be borne by the industry been recognized and subsequent minimal or no reliability benefit associated with meeting that requirement for local impact only schemes, the standard would not have been approved by the NERC BOT. Furthermore, the System Protection Coordination Subcommittee of NERC had specifically noted and suggested that 4 types of RAS are on the BES. Two of these were local and these categories were developed to afford the SDT to tailor specific and appropriate reliability and security requirements on these local type schemes. To broadly apply these more stringent requirements to all RAS on the new BES with the new RAS definition has little cost benefit. In addition, the existing PRC-012-0 and -1 only require a single component failure review and design requirement at the time of review. PRC-014-0 and -1, which are the SPS/RAS assessment standards currently do not require the Transmission Planner to include a requirement such as Requirement R4 Part 4.4 in their periodic assessment. The SDT has gone unnecessarily beyond the intent of the current standards in this regard.

In addition it should be noted that all existing RAS have gone through regional reviews and been approved for implementation. These existing RAS may not have met the existing single component failure requirement due to the revision of the BES. The regions each have a process for ensuring the reliability of the BES, and that the necessary level of reliability and security had been met at the time of approval. Furthermore, misoperation studies have not indicated that there is a reliability need to incorporate single component failure design into local systems. These local RAS which do not meet the requirement would need to be redesigned, outages taken, and then revisions made to come into compliance. This, in and of itself would represent a risk to the operation and reliability of the BES.

Requirement R4 Part 4.4 currently states;

“4.4 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 is designed.”

We suggest Part 4.4 be removed. However, if not removed, we propose the following:

4.4 A single component failure in the RAS, when the RAS is intended to operate, does not result in any of the following conditions on the BES:

- Cascading
- Uncontrolled System Separation
- Instability

The above modification would provide the necessary level of security and reliability to the BES. Ensuring that RAS installed on the BES or installed to meet TPL requirements would only be required when the RAS operation is critical, and any inadvertent operation results in a significant impact to the BES.

Response: Thank you for your comments.

The drafting team revised Requirement 4 to make the Planning Coordinator (PC) the responsible entity. The drafting team maintains that the PC does not need to know the detailed RAS design and can consult with the RAS-entity to ascertain the consequences of any single component failure. The drafting team maintains that the PC is the proper entity to perform the System performance evaluations listed in Requirement 4, Parts 4.1 through 4.4. The revisions to Requirement 4, Part 4.4 have effectively limited the number of RAS to be evaluated for single component failure and the amount of associated data the PC will need to obtain to perform the evaluation.

The drafting team agrees in principle with your comment and has revised Requirement 4, Part 4.4 to allow the Reliability Coordinator to determine whether a RAS has a "limited impact" and can therefore be exempted from Part 4.4 of the requirement. The drafting team also added an explanatory footnote and revised Attachments 1 and 2 to reflect the change in Part 4.4.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:	Yes
Answer Comment:	ERCOT supports the comments submitted by the ISO/RTO Council.
Response:	

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:	Yes

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer:	No
Answer Comment:	Single component failures should exclude station dc supply and some portions of communications systems (e.g., microwave towers and multiplexing equipment). Such exceptions have existed in the industry.

For a single component failure, it is unclear why the requirement was changed from simply having to meet the performance requirements defined in TPL standards to having to meet those required for the events and conditions for which the RAS is designed.

In the Q & A document, section 5, page 4, how can arming excess load and generation not impact reliability? TPL footnote 9 notes that "the planning process should be to minimize the likelihood and magnitude of interruption." RAS entities should be allowed to consider whether a 100% chance of tripping too much load/generation in the event of correct RAS operation really meets the intent of TPL. In some cases, allowing a single point failure to degrade the performance of the RAS is a better overall choice for minimizing total probability of interruption.

In the Q & A document, section 5, page 4, what kind of automatic actions are referenced? As the NERC reliability standards have evolved, the classification of RAS has expanded from just very high complexity protection schemes to now include many kinds of routine automatic actions. Almost any automatic action used to mitigate a TPL violation would become a RAS by virtue that it is used to meet requirements identified in a NERC Reliability Standard.

Response: Thank you for your comments.

The drafting team declines to identify RAS components that could be excluded from the single component failure aspect of the requirement. For new and modified RAS, single component failure design will be reviewed by the RC and any components subject to inclusion or exclusion will be determined at that time.

The drafting team used the words "meet those required for the events and conditions for which the RAS is designed" to be consistent with our understanding of the existing standard PRC-012-0. This also makes it clear that a RAS designed for an extreme event does not have to meet the performance requirements listed in the TPL standard.

Arming excess load and generation in a RAS is only allowed when tripping load or generation is allowed by TPL-001-4. If it is allowed by TPL-001-4, then it should not be affecting the reliability of the system (according to that standard). Allowing a single component failure to degrade the performance of the RAS may minimize the total probability of interruption. However, the RAS would have been designed and placed into service to solve some System performance issue. It is better to ensure that the System performance issue is satisfied for single component failures even if additional load or generation has to be armed for interruption.

Automatic actions may or may not be classified as a RAS. An example which would not be classified as a RAS would be a UVLS Program (consisting of only distributed relays) which is located in the same area as a RAS. The RAS was separately installed to solve a voltage problem in an area. The UVLS Program is not a RAS but the automatic action taken by the UVLS relays, assuming that load shedding is permissible for the event under the TPL standard, could provide the necessary relief if a single component of the RAS failed.

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:	No
Answer Comment:	At the present time there are RAS in service that have a limited local impact. To universally apply the same design criteria to all RAS regardless of their impact on BES in case of failure to operate may have no cost benefit in the case of the RAS installed to address local problems.

We propose the following to be included in the standard:

The failure of a RAS to operate does not result in any of the following conditions on the BES:

1. Cascading

2. Uncontrolled System Separation

3. Instability

When the criteria mentioned above is not met a redundant design will be required.

When a RAS is used to respond to an event, e.g. category P1 in TPL-001-4, its failure should be considered to be a more severe event, just as in TPL-001-4 the failure of a breaker or protection relay following a P1 event is recognized as “Multiple Contingency” (category P3 and P4). For this reason, the system performance with a RAS failure should not be required to meet the same requirements (defined in TPL-001-4) as those for the original event.

We suggest that the system performance requirement in case of failure of a single component of a RAS be limited to the following:

1. The BES shall remain stable

2. Cascading or Uncontrolled System Separation shall not occur

Response: Thank you for your comments.

The drafting team agrees in principle with your comment and has revised Requirement 4, Part 4.4 to allow the Reliability Coordinator to determine whether a RAS has a “limited impact” and can therefore be exempted from Part 4.4 of the requirement. The drafting team also added an explanatory footnote and revised Attachments 1 and 2 to reflect the change in Part 4.4.

The SDT agrees that a single component failure of a RAS during a P3 or P4 event has a low probability of occurrence. However, the SDT maintains that the single component failure requirement applies to contingencies in TPL-003 in the current standard. Not having the single component failure test apply to P3 or P4 events would be lowering the bar from the previous standard.

Richard Vine - California ISO - 2 -

Selected Answer: Yes

Answer Comment: The California ISO supports the comments of the ISO/RTO Standards Review Committee

Response: Please see the drafting team’s responses to the referenced comments.

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Dixie Wells - Lower Colorado River Authority - 5 -

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Selected Answer: Yes

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Selected Answer: Yes

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Yes

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer:	Yes
Rachel Coyne - Texas Reliability Entity, Inc. - 10 -	
Selected Answer:	Yes
Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3	
Selected Answer:	Yes
Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -	
Selected Answer:	No
Answer Comment:	When a RAS is used to respond to an event, e.g. category P1 in TPL-001-4, its failure should be considered to be a more severe event, just as in TPL-001-4 the failure of a breaker or protection relay following a P1 event is recognized as “Multiple Contingency” (category P3 and P4). For this reason, the system performance with a RAS failure should not be required to meet the same

requirements (defined in TPL-001-4) as those for the original event.

We suggest that the system performance requirement in case of failure of a single component of a RAS be limited to the following:

1. The BES shall remain stable

2. Cascading or Uncontrolled System Separation shall not occur

Please also see the following comments for relaxing the requirements for a class of RAS.

Response: Thank you for your comments.

The drafting team revised Requirement 4 to make the Planning Coordinator (PC) the responsible entity. The drafting team maintains that the PC does not need to know the detailed RAS design and can consult with the RAS-entity to ascertain the consequences of any single component failure. The drafting team maintains that the PC is the proper entity to perform the System performance evaluations listed in Requirement 4, Parts 4.1 through 4.4. The revisions to Requirement 4, Part 4.4 have effectively limited the number of RAS to be evaluated for single component failure and the amount of associated data the PC will need to obtain to perform the evaluation.

The drafting team agrees in principle with your comment and has revised Requirement 4, Part 4.4 to allow the Reliability Coordinator to determine whether a RAS has a “limited impact” and can therefore be exempted from Part 4.4 of the requirement. The drafting team also added an explanatory footnote and revised Attachments 1 and 2 to reflect the change in Part 4.4.

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer: Yes

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Selected Answer: No

Answer Comment: We recommend that the SDT consolidate the numerous sub-parts in Requirement R4, as they are confusing to both registered entity and auditor.

Response: Thank you for your comment.

The subparts of Requirement R4 are distinct components of the evaluation that must be made. The drafting team maintains that attempting to consolidate them would reduce clarity, not improve it.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

5. Corrective Action Plans: Do you agree that the application of Requirements R6 and R7 would address the reliability objectives associated with CAPs? If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:	Yes

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer:	No
Answer Comment:	We suggest that the RAS-owner be removed from the Requirements, and that only the RAS-entity be subject to these Requirements. See below for more comments.

Response: Thank you for your comment.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team contends that the RAS-entity as the asset owner, is in the best position to develop the actions and timelines necessary; i.e., schedule the work and submit clearances to perform the activities required to correct the deficiencies.

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment: AEP believes R6 should be further revised to clarify exactly when the “six calendar months” begins. We suggest revising it to state ”Within six-full-calendar months of *the RC* being notified of a deficiency…”

Response: Thank you for your comment.

The drafting team revised the requirement.

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments

Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: No

Answer Comment:

The NSRF recommends revising R6 to explicitly include the Planning Coordinator with working like, ". . . submit the CAP to its reviewing Reliability Coordinator and impacted Transmission Planners and Planning Coordinators". The inclusion of Transmission Planners and Planning Coordinators is appropriate because these entities will generally have the best planning horizon information and expertise to review the CAP.

Response: Thank you for your comment.

The drafting team asserts that the Reliability Coordinator is responsible for maintaining the operating reliability of the Bulk Electric System within its Reliability Coordinator Area. When a deficiency is identified, the Reliability Coordinator should make the decision whether or not to allow the RAS to remain in-service until the Corrective Action Plan is completed. As the drafting team has noted in responses to other comments, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the reviews if they believe it will enhance the quality and efficiency of the review process. This flexibility allows the RC to garner input from any impacted Transmission Planners and Planning Coordinators.

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment: There appears to be a gap between R6 and R7, from the point where each RAS owner submits a CAP to its RC, and then implementing the CAP. There should be a requirement placed upon the RC where a review of the CAP is completed and feedback provided to the RAS owner.

Response: Thank you for your comment.

The drafting team asserts that the Reliability Coordinator is responsible for maintaining the operating reliability of the Bulk Electric System within its Reliability Coordinator Area. When a deficiency is identified and a CAP is created, unless the CAP can be completed the same day, the Reliability Coordinator will most likely impose operating restrictions to ensure reliability until the RAS deficiency is resolved. The drafting team contends the RAS-entity will work closely with the RC to expedite the return to service date of the RAS. The drafting team asserts because the RC and RAS-entity have a mutual interest in returning the RAS to service as soon as possible to promote the reliability of the BES, their motivation and collaboration on this effort is sufficient, and does not necessitate the need for an additional requirement in the standard.

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3

Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Selected Answer: No

Answer Comment: The requirement R7 is very ambiguous about the time-frame for implementing a corrective action plan. Who approves the proposed schedule?

Response: Thank you for your comments.

Each CAP is unique and consequently the implementation and completion of each CAP will be unique as well. The RAS-entity submits the CAP to the reviewing RC. Although RC "approval" isn't mandated in a requirement, the RAS-entity must update the CAP if actions or timetables change, and communicate with the RC throughout CAP implementation and completion.

The drafting team asserts that the Reliability Coordinator is responsible for maintaining the operating reliability of the Bulk Electric System within its Reliability Coordinator Area. When a deficiency is identified and a CAP is created, unless the CAP can be completed the same day, the Reliability Coordinator will most likely impose operating restrictions to ensure reliability until the RAS deficiency is resolved. The drafting team contends the RAS-entity will work closely with the RC to expedite the return to service date of the RAS. The drafting team asserts because the RC and RAS-entity have a mutual interest in returning the RAS to service as soon as possible to promote the reliability of the BES, their motivation and collaboration on this effort is sufficient, and does not necessitate the need for an additional requirement in the standard.

Chris Scanlon - Exelon - 1 -

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Selected Answer: Yes

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: No

Answer Comment:	R6 and R7 should specify a CAP is created only if deficiency is on the RAS-owners part of the RAS. As written, all RAS-owners would be responsible for submitting CAPs if a single deficiency was identified on just one part of the RAS. As written, a RAS-owner would be responsible for writing a CAP and implementing the CAP for something they may have no control over, if the deficiency is on another RAS-owners part of the RAS.

Response: Thank you for your comments.

If there are no deficiencies found, then it is not necessary to develop a CAP. The definition of a Corrective Action Plan (CAP) in the Glossary of Terms Used in NERC Reliability Standards is: A list of actions and an associated timetable for implementation to remedy a specific problem. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities.

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer:	Yes

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: Yes

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment: Although the Corrective Action Plan (CAP) does address the reliability objectives it is unclear on the responsibilities of the parties involved. As the requirement is written, the Owner must submit the corrective action plan. There is a little confusion on any RAS that have multiple owners. Would ALL the owners need to submit a CAP or only the owner of the equipment in question? SRP recomends clarifying and possibly designating operator as the one to submit the CAP.

Response: Thank you for your comments.

If there are no deficiencies found, then it is not necessary to develop a CAP. The definition of a Corrective Action Plan (CAP) in the Glossary of Terms Used in NERC Reliability Standards is: A list of actions and an associated timetable for implementation to remedy a specific problem. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities.

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment: Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Response: Please see the drafting team's responses to the referenced comments.

David Greene - SERC - 1,10 - SERC

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Selected Answer: Yes

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer:	Yes

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:	No
Answer Comment:	ATC recommends revising R6 to explicitly include the Planning Coordinator with working like, ". . . submit the CAP to its reviewing Reliability Coordinator and any applicable Planning Coordinators". The inclusion of Planning Coordinators is appropriate because Planning Coordinators will generally have the best information and expertise to review the CAP.

Response: Thank you for your comment.

The drafting team asserts that the Reliability Coordinator is responsible for maintaining the operating reliability of the Bulk Electric System within its Reliability Coordinator Area. When a deficiency is identified, the Reliability Coordinator should make the decision whether or not to allow the RAS to remain in-service until the Corrective Action Plan is completed. As the drafting team has noted in responses to other comments, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the reviews if they believe it will enhance the quality and efficiency of the review process. This flexibility allows the RC to garner input from any impacted Transmission Planners and Planning Coordinators.

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: No

Answer Comment:

Requirement R6 reads as follows:

"Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)."

As written, R6 doesn't clearly assign the responsibility to the RAS-owner and only states they shall participate. Standard requirements need to be specific on who is responsible for what, and when. We also suggest that any CAP being submitted to the PC (we feel that the PC is appropriate as discussed in comments on R1) be a "mutually agreed upon" CAP. To address this issue we suggest the following:

Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to

Requirement R4 or Requirement R5, each RAS-owner shall develop a mutually agreed upon

Corrective Action Plan (CAP) with all affected Reliability Coordinators and submit the CAP to its reviewing Planning Coordinator(s).

We suggest that the full responsibility of the development of the CAP rest with the RAS-entity. The rationale box states this but it needs to be clear in the requirement. Irrespective of complexity, the need to collaborate with others and hire consulting services, the responsibility should rest solely on the RAS-owner.

Also there may be a need for an additional requirement to notify the PC and TOP when the CAP has been completed, and the RAS is performing correctly. We will leave this for consideration by the SDT and believe this brings specific closure to any RAS deficiency.

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities. The drafting team declines to make the suggested change.

Standard utility practice as well as other NERC Reliability Standards ensure the TOP and PC will be aware of the CAP completion.

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: No

Answer Comment: As mentioned in our previous comments, Peak recognizes that the RC or TOP may impose operating restrictions to ensure reliability until the RAS deficiency is resolved but maintains that the CAP should be reviewed by an independent party to assure that it addresses the reliability issues in a reasonable timeframe. . For example, a CAP could be created with an unreasonable timeframe that unnecessarily extends a reliability issue. This independent review by the RC and subsequent required action by the RAS-entity exists for new RAS but not for CAPs, which appears inconsistent with the intent of the Standard. A process similar to that described in R2 and R3 should also apply to CAPs and not just new and functionally modified RAS.

Response: Thank you for your comment.

The drafting team asserts that the Reliability Coordinator is responsible for maintaining the operating reliability of the Bulk Electric System within its Reliability Coordinator Area. When a deficiency is identified, the Reliability Coordinator should make the decision whether or not to allow the RAS to remain in-service until the Corrective Action Plan is completed. As the drafting team has noted in responses to other comments, the RC has the “flexibility” to request information or assistance from relevant entities (third parties) to participate in the reviews if they believe it will enhance the quality and efficiency of the review process. This flexibility allows the RC to garner input from any impacted Transmission Planners and/or Planning Coordinators.

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Selected Answer:	No
Answer Comment:	We suggest the following rewording: “Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall develope a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s).” R6 should reflect that it is either solely the RAS owner’s responsibility **or** both the RC and RAS owner must have responsibility and “participate” in developing the CAP together. If the CAP requires mutual participation to develop, then both parties (the RAS owner AND the RC) must have compliance responsibility.

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities. The drafting team declines to make the suggested change.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Selected Answer: Yes

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: No

Answer Comment: Reclamation suggests that the RAS-entity should be responsible for the Corrective Action Plans (CAPs) called for in requirements R6 and R7. Each RAS-owner should not be responsible for developing CAPs and coordinating them with the Reliability Coordinator (RC) because this could result in duplication of efforts or inconsistent corrective actions. As outlined in the Technical Justifications, “[t]he purpose of the RAS-entity is to be the single information conduit with each reviewing Reliability Coordinator (RC) for all RAS-owners for each RAS.” When there are several owners involved in a RAS, the RC should communicate with the RAS-entity as one point of contact to ensure that an overall CAP addresses any RAS deficiencies.

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities. The drafting team declines to make the suggested change.

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2

Ali Miremadi	CAISO	WECC	2

Selected Answer: No

Answer Comment: The SRC agrees that the RAS entity should develop Corrective Action Plans to evaluate RASs to address issues and/or deficiencies identified by their evaluations, but would suggest that such entities be required to provide the Corrective Action Plans to their Reliability Coordinator ***and Planning Coordinator*** for review.

Response: Thank you for your comment.

The drafting team asserts that the Reliability Coordinator is responsible for maintaining the operating reliability of the Bulk Electric System within its Reliability Coordinator Area. When a deficiency is identified, the Reliability Coordinator should make the decision whether or not to allow the RAS to remain in-service until the Corrective Action Plan is completed. As the drafting team has noted in responses to other comments, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the reviews if they believe it will enhance the quality and efficiency of the review process. This flexibility allows the RC to garner input from any impacted Transmission Planners and Planning Coordinators. The drafting team declines to make the suggested change.

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment: See comment in no. 7.

Response: Please see the drafting team's responses to the referenced comment.

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment: "Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)."

As written, R6 doesn't clearly assign the responsibility to the RAS-owner and only states they shall participate. Standard requirements need to be specific on who is responsible for what, and when. We also suggest that any CAP being submitted to the RC be a "mutually agreed upon" CAP. To address this issue we suggest the following:

Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall develop a mutually agreed upon Corrective Action Plan (CAP) with all affected Reliability Coordinators and submit the CAP to its reviewing

Reliability Coordinator(s).

We suggest that the full responsibility of the development of the CAP rest with the RAS-owner. The rationale box states this but it needs to be clear in the requirement. Irrespective of complexity, the need to collaborate with others and hire consulting services, the responsibility should rest solely on the RAS-owner.

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities. The drafting team declines to make the suggested change.

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments

Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: Yes

Answer Comment:

Attachment 1, Section III-Implementation states, "5. Documentation describing the functional testing process." Dominion recommends deleting this bullet. This information is not necessarily available during the preliminary design phase. The approval of the design is sought prior to detailed engineering. (Planning)

In R5 it states that the RAS owner analyzes the event, but in flow chart it states RAS owner and TP. Dominion suggests that the content in the Flow Chart be consistent with language of the Requirement.

R5 references the timeframe "within 120 calendar days", however in other areas of the document the time frame is stated to be "within XX calendar months". Dominion suggests updating the document to reflect the actual timeframe. Dominion also believes clarification is needed to establish "full calendar months" versus "months".

Response: Thank you for your comments.

The drafting team maintains that sufficient information must be provided to the RC to allow a proper review including information describing the RAS-entity's plan for periodic testing. The drafting team declines to make the suggested change.

The drafting team made the change to the flowchart.

The drafting team modeled the requirement after the requirements of PRC-004. The drafting team maintains that the time increment of 'days' rather than 'months' is preferable for this requirement and declines to make the suggested change.

The drafting team uses the clarifier 'full' to be clear that partial time increments are not counted. For example, for four calendar months, if the starting point is in the middle of a calendar month (October 15), four full calendar months would begin November 1 and continue through February 28 (the last day of the month of the stated period).

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Selected Answer:	No
Answer Comment:	See the comments in #2, which is critical to R6. Furthermore, the team should modify the R6 phrase as shown below: "…each RAS-owner shall participate in developing a Corrective Action Plan with the RAS-entity which shall and submit the CAP to its reviewing Reliability Coordinator…." This will result in one RAS-entity submitted CAP to the reviewing RC.

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities. The drafting team declines to make the suggested change.

Likes:	4	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla PSEG - PSEG Fossil LLC, 5, Kucey Tim PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	**Entity**	**Region**	**Segments**
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1

Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Selected Answer: No

Answer Comment:	Requirement R6 reads as follows: "Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)." As written, R6 doesn't clearly assign the responsibility to the RAS-owner and only states they shall participate. Standard requirements need to be specific on who is responsible for what, and when. We also suggest that any CAP being submitted to the RC be a "mutually agreed upon" CAP. To address this issue we suggest the following: Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner and affected Reliability Coordinator(s) shall develop a mutually agreed upon Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s). Also, there may be a need for an additional requirement to notify the RC and TOP when the CAP has been completed, and the RAS is performing correctly. This should be considered by the SDT. This brings specific closure to any RAS deficiency. Requirement R5 stipulates that the RAS-owner identifies deficiencies to its reviewing RC. Suggest R6 be revised to read: "Within six-full-calendar months of identifying or of being notified of a…"

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities. The drafting team declines to make the suggested change.

The drafting team revised Requirement R7 to include the notification of each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

The drafting team revised Requirement R6.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:	No
Answer Comment:	ERCOT supports the comments submitted by the ISO/RTO Council.

Response: Please see the drafting team's responses to the referenced comments.

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: Yes

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: Yes

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer: No

Answer Comment: TANC has concerns with the current language in R5, R6, and R7, because it appears these requirements would assign the same or similar responsibilities to "each RAS-owner" when a single RAS operates or fails to operate as expected. In circumstances where a single RAS has multiple RAS-owners, the current language would potentially create overlapping responsibilities to analyze the RAS performance and develop/implement a Corrective Action Plan. It seems that these

	responsibilities established in R5, R6, and R7 would be more appropriately assigned to the single RAS-entity for a RAS rather than to each RAS-owner.

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Requirements R5 and R6 do require each RAS-entity to perform the actions associated with the requirements. The drafting team maintains this will promote reliability and that entities will not duplicate efforts. Each entity is responsible only for its RAS components. The drafting team is confident that entities will communicate with each other if there is any question or doubt of responsibility. The drafting team declines to make the suggested change.

The drafting team revised Requirement R7 to include the notification of each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

The drafting team revised Requirement R6.

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:	No

Answer Comment:	Requirement R6 reads as follows: “Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s).” As written, R6 doesn’t clearly assign the responsibility to the RAS-owner and only states they shall participate. Standard requirements need to be specific on who is responsible for what, and when. We also suggest that any CAP being submitted to the RC be a “mutually agreed upon” CAP. To address this issue we suggest the following: Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall develop a mutually agreed upon Corrective Action Plan (CAP) with all affected Reliability Coordinators and submit the CAP to its reviewing Reliability Coordinator(s). We suggest that the full responsibility of the development of the CAP rest with the RAS-owner. The rationale box states this but it needs to

be clear in the requirement. Irrespective of complexity, the need to collaborate with others and hire consulting services, the responsibility should rest solely on the RAS-owner.

Requirement R6 states, "Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5…", however, a notification does not come out of R5 since the applicability to both R5 and R6 is with the RAS owner.

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities. The drafting team declines to make the suggested change.

The drafting team revised Requirement R6.

Richard Vine - California ISO - 2 -

Selected Answer: No

Answer Comment: The California ISO supports the comments of the ISO/RTO Standards Review Committee

Response: Please see the drafting team's responses to the referenced comments.

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Andrew Gallo - Austin Energy - 6 -

Selected Answer: Yes

Dixie Wells - Lower Colorado River Authority - 5 -

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments

Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Selected Answer: Yes

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Selected Answer: Yes

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:	Yes
Don Schmit - Nebraska Public Power District - 5 -	
Selected Answer:	Yes
Jeff Wells - Grand River Dam Authority - 3 -	
Selected Answer:	Yes
Rachel Coyne - Texas Reliability Entity, Inc. - 10 -	
Selected Answer:	No
Answer Comment:	Texas RE is concerned there could be an extended time frame where a RAS with a known deficiency will be in service since the requirement to develop a Corrective Action Plan (CAP) is do so within six months. Texas

RE is also concerned there is no defined time frame for implementing the CAP.

Response: Thank you for your comments.

The drafting team disagrees that there is a reliability risk during the time interval associated with the CAP development though completion of the CAP because the Reliability Coordinator will require the RAS-entity to modify operating procedures, System configuration, generation dispatch, or employ other methods to alleviate the deficient RAS. The RAS review associated with new or functionally modified RAS is a more comprehensive review that entail the design, operations, and testing of the RAS.

The definition of a Corrective Action Plan (CAP) in the Glossary of Terms Used in NERC Reliability Standards is: A list of actions and an associated timetable for implementation to remedy a specific problem. Each CAP is unique and consequently the implementation and completion of each CAP will be unique as well. The RAS-entity submits the CAP to the reviewing RC. Although RC "approval" isn't mandated in a requirement, the RAS-entity must update the CAP if actions or timetables change, and communicate with the RC throughout CAP implementation and completion.

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Selected Answer: No

Answer Comment: The RC needs to be given the authority to reject the CAP, or suggest changes to the CAP.

Response: Thank you for your comment.

The RAS-entity must submit the CAP and other Attachment 1 information to the RC if functional modifications to the RAS are proposed. Accordingly, pursuant to Requirement R3, the RAS-entity must obtain approval of the RAS from each reviewing Reliability Coordinator.

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:	No
Answer Comment:	Hydro One Networks Inc. believes that as quoted below, R6 does not clearly assign the responsibility to the RAS-owner and only states that they “shall participate”. “Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s).” Standard requirements need to be specific on as to who is responsible for what, and when. We also suggest that any CAP being submitted to the RC be a “mutually agreed upon” CAP. To address these issues, we suggest revising the wording to read the following: “Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirements R4 and R5 state that each RAS-owner shall develop with all affected RCs, a mutually agreed upon Corrective

	Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)". However, Hydro One Networks Inc. suggests that the full responsibility of the development of the CAP rest with the RAS-owner. The rationale box states that the full responsibility of the development of the CAP rests with the RAS-owner, but this needs to be clear, and explicitly stated in the requirement as well. Irrespective of complexity, the need to collaborate with others, hire consulting services, etc., the responsibility should rest solely on the RAS-owner. Requirement R6 states, "Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5…", however, Hydro One would like to point out that a notification does not result from requirement R5 since the applicability to both R5 and R6 is with the RAS owner themselves.

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities. The drafting team declines to make the suggested change.

The drafting team revised Requirement R6.

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer: No

Answer Comment: The RAS-entity should be included in Requirements R6 and R7 in a coordinating role between the RAS-owners and the TP and/or RC. It should be made clear that the RAS-owners are only responsible for their portion of the RAS.

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities.

Requirement R7 mandates each RAS-entity to implement its portion of the RAS.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments

Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Selected Answer: No

Answer Comment: We disagree with the SDT that there needs to be two requirements to cover CAPs. These requirements should be consolidated and simplified to avoid unnecessary confusion and potential compliance impacts. Furthermore, CAPs are administrative in nature and we recommend removing these requirements under Paragraph 81 Administrative criteria.

Response: Thank you for your comments.

The drafting team maintains there are separate and distinct reliability objectives associated with the two requirements that reference CAPs and declines to combine them.

The drafting team disagrees that CAPs are administrative in nature, no changes made.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

6. Implementation Plan: Do you agree with the Implementation Plan? If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	**Entity**	**Region**	**Segments**
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6

Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: Yes

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Chris Scanlon - Exelon - 1 -

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Selected Answer: Yes

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC **Selected Answer:** Yes
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP **Selected Answer:** Yes
Molly Devine - IDACORP - Idaho Power Company - 1 - **Selected Answer:** Yes
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC **Selected Answer:** No

Answer Comment: SRP notices possible confusion on the implementation for R4 and R8. The rationale for R4 and R8 state that the 60 month time period begins on the effective date of the standard. However, the implementation plan does not state that similarly. There is potential confusion for this as many entities are likely to attempt to have their evaluations and functional tests completed by the effective date.

Response: Thank you for your comment.

The 60 full calendar month interval in Requirement R4 and the six calendar year interval in Requirement R8 both begin on the effective date of PRC-012-2. The initial performance of those requirements must be completed within the specified interval after the effective date of PRC-012-2. The drafting team added language to the Implementation Plan to provide additional clarity.

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment: Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Response: Please see the drafting team’s responses to the referenced comments.

David Greene - SERC - 1,10 - SERC

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Selected Answer: Yes

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer: Yes

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: Yes

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment: Peak interprets the Implementation Plan as grandfathering in all existing RAS, which means review and approval of existing RAS is not required – only for new or modified RAS. The revised Standard does not address existing RAS, and therefore neglects any potential reliability issues associated with them. Peak seeks clarity on this issue.

Response: Thank you for your comment.

The standard addresses all RAS. Requirements R1, R2, and R3 address new or functionally modified RAS. Requirements R4, R5, and R8 pertain to all RAS. Existing RAS are not grandfathered; however, they would not need to go through the new RAS-review process (Requirements R1, R2, and R3) until such time that a functional modification was required due to an issue identified via Requirements R4, R5, or R8. The functional modification would be described and submitted to the reviewers via a Corrective Action Plan (CAP) in conjunction with Requirement R6.

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Selected Answer: Yes

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Selected Answer:	Yes
Mike Smith - Manitoba Hydro - 1 -	
Selected Answer:	Yes
Erika Doot - U.S. Bureau of Reclamation - 5 -	
Selected Answer:	Yes
Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -	
Selected Answer:	Yes
Oliver Burke - Entergy - Entergy Services, Inc. - 1 -	

Selected Answer: Yes

Answer Comment: See comment in no. 7.

Response: Please see the drafting team's responses to the referenced comment.

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment: The Implementation Plan should be modified to include clarification for implementation of R4. TFSP suggests adding the language used in the Rationale box for R4, which says: "Sixty-full-calendar months, which begins on the effective date of the standard pursuant to the implementation plan…"

The standard or the Implementation Plan should allow the RAS-owner sufficient time to mitigate a design deficiency identified as part of R4, such as the lack of redundancy without removing the RAS from service. Clarification should be provided to allow for continued operation of an existing RAS after a single component failure scenario is identified until a Corrective Action Plan can be completed.

Response: Thank you for your comments.

The 60 full calendar month interval in Requirement R4 begins on the effective date of PRC-012-2. The initial performance of the requirement must be completed within the specified interval after the effective date of PRC-012-2. The drafting team added language to the Implementation Plan to provide additional clarity.

The drafting team asserts that the Reliability Coordinator is responsible for maintaining the operating reliability of the Bulk Electric System within its Reliability Coordinator Area. If a design deficiency is identified as part of the Requirement R4 planning evaluation, the Planning Coordinator in conjunction with the Reliability Coordinator should make the decision whether or not to allow the RAS to remain in-service until the Corrective Action Plan is completed.

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: Yes

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Selected Answer: No

Answer Comment: The effective date in Implementation Plan should be increased from 12 month to 36 months after the first day of the first calendar quarter after the date the standard is approved. This reason for this delay is that standard establishes a new working framework between RAS-owners, RAS-entities, TPs, and RCs. That itself will involve considerable start-up effort. In return for this added delay, the first periodic review of each

RAS under R4 could be due within 36 months, with subsequent reviews every 60 months.

Response: Thank you for your comment.

The drafting team lengthened the implementation period of the standard to thirty-six months to provide entities adequate time to establish the new working frameworks.

Likes: 4 PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3

Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10

Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1

Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Selected Answer: No

Answer Comment:

The Implementation Plan should be modified to include clarification for implementation of R4. Suggest adding the language used in the Rationale for Requirement R4, which says: “Sixty-full-calendar months, which begins on the effective date of the standard pursuant to the implementation plan…”

The standard or the Implementation Plan should allow the RAS-owner sufficient time to mitigate a design deficiency identified as part of R4, such as the lack of redundancy without removing the RAS from service. Clarification should be provided to allow for continued operation of an existing RAS after a single component failure scenario is identified until a Corrective Action Plan can be completed.

The Implementation Plan should address the possible scenario of a RAS misoperation occurring within 120 days of the Standard's effective date, and if R5 would apply. Would this misoperation require the development of a CAP after the effective date of the Standard? This would apply for R6 and R7 as well.

For testing records will the RAS-owner need to have documentation of testing prior to the standard's effective date? This should be clarified in the Implementation Plan.

Response: Thank you for your comments.

The 60-full calendar month interval in Requirement R4 begins on the effective date of PRC-012-2. The initial performance of the requirement must be completed within the specified interval after the effective date of PRC-012-2. The drafting team added language to the Implementation Plan, rationale box, and Supplemental Material section of the standard to provide additional clarity.

The drafting team asserts that the Reliability Coordinator is responsible for maintaining the operating reliability of the Bulk Electric System within its Reliability Coordinator Area. If a design deficiency is identified as part of the Requirement R4 planning evaluation, the Planning Coordinator in conjunction with the Reliability should make the decision whether or not to allow the RAS to remain in-service until the Corrective Action Plan is completed.

Requirement R4 states that the entity shall analyze the RAS performance and provide the results of the analysis, including any identified deficiencies, to its reviewing Reliability Coordinator(s) within 120 calendar days of a RAS operation or failure of a RAS to operate when expected; therefore, the effective date of the standard is irrelevant. Yes, Requirements R6 and R7 mandate a Corrective Action Plan be developed, submitted, and implemented.

The functional testing of a RAS is a new requirement; consequently, no records of functional testing prior to the effective date of the standard are required.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Answer Comment: N/A

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: No

Answer Comment: In the Implementation Plan, page 2, the following sentence has a grammatical/mechanical issue: “As of the date of posting of this Implementation Plan, however, the Commission has not issued an Final Order approving and retirement the Reliability Standards enumerated above.”

Response: Thank you for your comment.

The drafting team revised the language to reflect the issuance of FERC Order 818 approving the proposed standards and definition of “Remedial Action Scheme.”

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer:	Yes

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:	No
Answer Comment:	The Implementation Plan should allow the RAS-owner sufficient time to mitigate a design deficiency identified as part of R4, such as the lack of redundancy without removing the RAS from service. Clarification should be provided to allow for continued operation of those RAS, that are already in service when the standard becomes effective, after a single component failure scenario is identified until a Corrective Action Plan can be completed.

Response: Thank you for your comment.

The drafting team asserts that the Reliability Coordinator is responsible for maintaining the operating reliability of the Bulk Electric System within its Reliability Coordinator Area. If a design deficiency is identified as part of the Requirement R4 planning evaluation, the Planning Coordinator in conjunction with the Reliability Coordinator should make the decision whether or not to allow the RAS to remain in-service until the Corrective Action Plan is completed.

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Andrew Gallo - Austin Energy - 6 -

Selected Answer: Yes

Dixie Wells - Lower Colorado River Authority - 5 -

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Selected Answer: Yes

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Selected Answer: Yes

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Yes

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Selected Answer: Yes

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment: The Implementation Plan should be modified to include clarification for implementation of R4. Hydro One Networks Inc. agrees with the NPCC's TFSP in adding the language used in the Rationale box for R4, which says: "Sixty-full-calendar months, which begins on the effective date of the standard pursuant to the implementation plan…"

The standard or the Implementation Plan should allow the RAS-owner sufficient time to mitigate a design deficiency identified as part of R4, such as the lack of redundancy without removing the RAS from service. Clarification should be provided to allow for continued operation of an existing RAS after a single component failure scenario is identified until a Corrective Action Plan can be completed.

Response: Thank you for your comments.

The 60 full calendar month interval in Requirement R4 begins on the effective date of PRC-012-2. The initial performance of the requirement must be completed within the specified interval after the effective date of PRC-012-2. The drafting team added language to the Implementation Plan, rationale box, and Supplemental Material section of the standard to provide additional clarity.

The drafting team asserts that the Reliability Coordinator is responsible for maintaining the operating reliability of the Bulk Electric System within its Reliability Coordinator Area. If a design deficiency is identified as part of the Requirement R4 planning evaluation, the Planning Coordinator in conjunction with the Reliability Coordinator should make the decision whether or not to allow the RAS to remain in-service until the Corrective Action Plan is completed.

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer: Yes

Answer Comment: The Implementation Plan should specify when the first 5 year evaluation required by R4 should be completed for an existing RAS.

Response: Thank you for your comment.

The 60 full calendar month interval in Requirement R4 begins on the effective date of PRC-012-2. The initial performance of the requirement must be completed within the specified interval after the effective date of PRC-012-2. The drafting team added language to the Implementation Plan, rationale box, and Supplemental Material section of the standard to provide additional clarity.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1

Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Selected Answer: No

Answer Comment: We ask the SDT to clarify whether the approval process and the first technical evaluation needs to be performed before or after the effective date of the standard.

Response: Thank you for your comment.

The approval process associated with the RAS review can only take place after the effective date of the standard. The 60 full calendar month interval in Requirement R4 begins on the effective date of PRC-012-2. The initial performance of the requirement must be completed within the specified interval after the effective date of PRC-012-2. The drafting team added language to the Implementation Plan, rationale box, and Supplemental Material section of the standard to provide additional clarity.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

7. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Answer Comment: We suggest that the standard have applicability to only the RAS entity, normally the primary Transmission Owner for the region affected. Including more than one party will make this standard too cumbersome and difficult to manage. The primary application of a RAS is to multi-facility, wide-area disturbances and as such is best vested in the Transmission Owner, who has a wider "system" viewpoint than the Generator Owner. We are concerned that Generator Owners may become inadvertent RAS-owners simply by owning a small fraction of the equipment needed for the RAS, and thus become subject to requirements R5 through R8, when they are typically passive parties to the RAS.

Response: Thank you for your comment.

The drafting team maintains that RAS-ownership should be according to component ownership. The RAS-entity owns the components that make up a RAS, and as the asset owner, is responsible for the purchase, design, operation, maintenance, and testing of a RAS. This includes protection system components as well as non-protection system components. Otherwise, components may be left out of functional testing (R8), from single component failure and malfunction evaluations (R4.1.3 and R4.1.4), and from operational analysis (R5) leading to reliability gaps.

Based on comments, the drafting team revised the standard such that Requirements R5 and R6 apply to the RAS-entity. The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. As explained in the Technical Justification, each separate RAS-entity is obligated to participate in various activities, as identified by the Requirements to the extent of their ownership. It is not the intent of the drafting team, however, to specify how multiple RAS-entities must coordinate.

John Fontenot - Bryan Texas Utilities - 1 -

Answer Comment: na

Emily Rousseau - MRO - 1,2,3,4,5,6 – MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5

Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Answer Comment: For R5, we propose revised wording that "within 120 days, or on a mutually agree upon schedule." This would allow earlier or later completion of the analysis when warranted by unusual circumstances.

Response: Thank you for your comment.

The drafting team made the suggested change.

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Answer Comment:

With regards to R5:

What is the benefit of providing the reviewing RC with results of a successful RAS operation?

With regards to R8:

Although functional testing would verify that the scheme is working as designed, there is no reason to believe that an RAS is any different from another protection system i.e., it would need to be tested at intervals outside the normal maintenance program. The testing of RAS should fall in line with PRC-005-3 requirements for monitored systems and unmonitored systems.

By requiring “at least once every six calendar years, each RAS-owner shall perform a functional test,” the drafting team is forcing all owners of a RAS that has any Protection Systems in it to abandon the PRC-005-3 12 year Maximum Maintenance Intervals allowed in tables 1-1, 1-2, 1-3, 1-5, and 4.

If Requirement R9 is adopted as stated in this draft of the standard, each segment of a RAS would have to be tested at a maximum interval of 6 calendar years. This would require, for example, that voltage and current sensing devices providing inputs to protective relays of a RAS "shall" be tested "at least once every six calendar years" instead of 12 Calendar years allowed in Table 1-3 of PRC-005-3.

Response: Thank you for your comments.

The drafting team revised the standard to state that Requirement R5 only requires a RAS-entity to provide the results of RAS operational performance analysis if deficiencies were identified. Please see the revised requirements and complementary revisions to the measures, rationale boxes, supplemental materials, and Attachments.

The drafting team revised the standard to allow RAS that have limited impact to have functional testing intervals of up to twelve full calendar years. However, the drafting team contends that the six full calendar year interval is appropriate for the higher impact RAS given the potential negative impact to BES reliability should a RAS operate incorrectly. Existing regional practices include more frequent RAS functional testing than the proposed six full year calendar interval. Requirement 8 in PRC-012-2 is only applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers (PLCs), personal computers (PCs), multi-function programmable relays, remote terminal units (RTUs), and logic processors that have no applicability within PRC-005.

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 – WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1

Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Answer Comment:

1. We ask for a clarification on the PRC-012-2 definition of RAS Owner to only “exclusively” include the owner of the scheme, and not include a “participating” entity in the RAS operation. The participating entity equipment would be covered by other standards such PRC-005-2 and thus should be excluded from standard.

2. The requirement R8 will require that the RAS is tested every 6 years, which is equivalent to any unmonitored relays that we have under PRC-005. However, testing the RAS may prove to be more laborious since it will most likely require coordination among multiple participating entities, so a more relaxed test sequence (12 years) would be preferred.

Response: Thank you for your comments.

Because of confusion between the terms, the drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If the individual owners of a RAS decide that it would be advantageous for one RAS-entity to represent all of the other owners and assume a lead role in performing some of the required tasks, the standard does not prohibit this type of arrangement. Nevertheless, each RAS-entity must still be able to demonstrate compliance with the individual requirements the standard.

The drafting team revised the standard to allow RAS that have limited impact to have functional testing intervals of up to twelve full calendar years. However, the drafting team contends that the six full calendar year interval is appropriate for the higher impact RAS given the potential negative impact to BES reliability. Existing regional practices include more frequent RAS functional testing than the proposed six full calendar year interval.

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Answer Comment:

RAS-entity should be responsible for R5 instead of RAS-owner. The RAS-entity, being designated to represent all RAS-owners, is in the best position to evaluate the operation of a RAS.

RAS-entity should be responsible for R8 functional testing.

R9 should include a sub-requirement for RCs to share their database with neighboring RCs to provide coordination of RAS schemes near RC borders.

Response: Thank you for your comments.

Because of confusion between the terms, the drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If the individual owners of a RAS decide that it would be advantageous for one RAS-entity to represent all of the other owners and assume a lead role in performing some of the required tasks, the standard does not prohibit this type of arrangement. Nevertheless, each RAS-entity must still be able to demonstrate compliance with the individual requirements the standard.

The drafting team asserts that there is not a need for a requirement in PRC-012 for an RC to share its RAS database because information sharing among neighboring RCs is already covered in other NERC Reliability Standards.

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Answer Comment:

There are numerous references to components of a RAS scheme in the standard and supplemental material, but there is no clear definition of what constitutes a component of a RAS scheme. A lack of a clear definition can lead to different interpretations of what a RAS component is. For example, Requirement R4.3 requires that "the possible inadvertent operation of the RAS resulting from any single RAS component malfunctions satisfies all of the following" conditions in 4.3.1 thru 4.3.5. While it is implied that the RAS components could include elements such as the RAS controller, communications, control circuitry, supervisory relays or functions (breaker 52A contact), and/or voltage or current sensing devices, it is not clearly stated. This leaves it open for some entities to possibly consider additional items such as a circuit breaker as a RAS component and other entities to not consider it. It could also allow some entities to take a more relaxed approach and exclude components that should possibly be included. A definition or explanation of RAS components should be added to the standard similar to the definitions used in PRC-005-4 (i.e. Automatic Reclosing and Sudden Pressure Relaying).

Response: Thank you for your comments.

The drafting team maintains that the team should not attempt to develop an exhaustive list of RAS components. An exhaustive list of components is not practical given the variety that could be applied in RAS design and implementation. See Item 4a in the Implementation Section of Attachment 1 in the Supplemental Material section for typical RAS components for which redundancy may be considered. The RAS-entity should have a clear understanding of what components were applied to put a RAS into service and which were already present in the system before a RAS was installed. The RC will make the final determination regarding which components should be regarded as RAS components during its review.

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Answer Comment:	Currently as the standard is written, R5 and R6 require each RAS-owner to submit the results of the analysis and a CAP if needed. Tri-State does not believe it should be required that each RAS-owner submit the results and/or CAP rather than the RAS-entity. The RAS-entity can collect the results and submit 1 report/CAP, instead of several individual submittals from the seperate RAS-owners. Also, Tri-State believes there is a numbering issue in Section II of Attachment 1 of the standard. It looks like "Documentation showing that the possible inadvertent operation of the RAS resulting from any singles RAS component malfunction satisfies all of the following:" should be #5 since it is a separate topic from #4.

Response: Thank you for your comments.

Based on comments, the drafting team revised the standard such that R5 and R6 requirements apply to the RAS-entity. The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. As explained in the Technical Justification, each separate RAS-entity is obligated to participate in various activities, as identified by the Requirements to the extent of their ownership. It is not the intent of the drafting team, however, to specify how multiple RAS-entities will coordinate.

The drafting team made the edit.

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer Comment:

a. The Rationale Box for R6 states that the “RAS-owner” will need to submit information in Attachment 1 to the RC, should this be the RAS-entity?

b. In R6, if the RAS-owner is the entity that performed the analysis in R4 of R5, when does the 6 month clock start (i.e., when was it notified)?

c. For R7, is the intent that each RAS-owner update the CAP with the RC? It seems like this should be the job of the RAS-entity, not multiple RAS-owners.

Response: Thank you for your comments.

Because of confusion between the terms, the drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If the individual owners of a RAS decide that it would be advantageous for one RAS-entity to represent all of the other owners and assume a lead role in performing some of the required tasks, the standard does not prohibit this type of arrangement. Nevertheless, each RAS-entity must still be able to demonstrate compliance with the individual requirements the standard.

The drafting team revised Requirement R6 for clarification.

Yes, each RAS-entity must implement the CAP as it relates to its facilities. The drafting team disagrees that only one entity needs to be responsible.

Joshua Andersen - Salt River Project - 1,3,5,6 – WECC

Answer Comment:

As written the rationale for R8 is not incorporated into the requirement. R8 rationale states that correct operation of a RAS segment would qualify as a functional test. Please state that in the requirement so there is no confusion or debate if a correct operation resets the time frame necessary to perform a test.

SRP recommend the removal of the word “Requirement” in front of any R# designation. R1 stands for Requirement 1 and is sufficient. Saying "Requirement R1" is like saying Requirement Requirement 1. Also, the term “Requirement” is not a defined term.

Response: Thank you for your comments.

The drafting team added language to the measure for Requirement 8 indicating that a correct operation of a RAS segment would qualify as a functional test and the time frame for the segment that operated correctly would be reset. Segments that did not operate must be tested according to the planned testing schedule. In addition, the team will include that in the RSAW for PRC-012, Requirement R8.

The drafting team is adhering to the NERC style guide for Reliability Standards. Please address your comment to the appropriate NERC staff.

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer Comment: Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Response: Please see the drafting team's responses to the referenced comments.

David Greene - SERC - 1,10 - SERC

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1

David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Answer Comment: If a RAS has multiple owners, and one or more owners is not compliant to R8, does this mean that all owners, or the RAS-entity, are non-compliant?

Response: Thank you for your comments.

Because of confusion between the terms, the drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If the individual owners of a RAS decide that it would be advantageous for one RAS-entity to represent all of the other owners and assume a lead role in performing some of the required tasks, the standard does not prohibit this type of arrangement. Nevertheless, each RAS-entity must still be able to demonstrate compliance with the individual requirements of the standard.

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Answer Comment: IMEA questions the need to include DP in the applicability. It is likely a DP will only own a part of a RAS. It should be adequate to specify TO coordination to verify RAS performance.

In R8, IMEA recommends deletion of "...and the proper operation of non-Protection System components."; i.e., it should be adequate to indicate only "...verify overall RAS performance."

Response: Thank you for your comments.

The drafting team declines to make the suggested change removing the Distribution Provider (DP). Given the critical nature of RAS, every DP that owns all or part of a RAS must be held accountable to ensure BES reliability.

The focus of this requirement is verification of RAS functionality. Protection System components are addressed by PRC-005, but non-Protection System components such as programmable logic controllers are not applicable under PRC-005 so the drafting team is including them in PRC-012. The drafting team declines to make the suggested change.

Andrew Pusztai - American Transmission Company, LLC - 1 -

Answer Comment:

• For R5, ATC proposes revising wording that "within 120 days, or on a mutually agree upon schedule." This would allow earlier or later completion of the analysis when warranted by unusual circumstances.
• The purpose of Version 2 of PRC-005 was to consolidate all maintenance and testing of relays under one Standard. Having RAS testing within PRC-012-2 would be contrary to that end. ATC addresses this concern as follows:

Functional testing of RAS (as stated in Requirement 8 of PRC-012-2) is a maintenance and testing activity that would be better included in the PRC-005 standard. The present PRC-005-2 Reliability Standard is the maintenance standard that replaces PRC-005-1, 008, 011 and 017 and was designed to cover the maintenance of SPSs/RASs. However, Reliability Standard PRC-005-2 lacks intervals and activities related to non-protective devices such as programmable logic controllers. ATC recommends that a requirement for maintenance and testing of non-protective RAS components be added to a revision of PRC-005-2, rather than be an outlying maintenance requirement located in the PRC-012-2 Standard.

Response: Thank you for your comments.

The drafting team made the suggested change.

The functional testing of a RAS to verify its performance is different from the maintenance activities associated with the Protection System Components as detailed in the tables of PRC-005. Requirement 8 of PRC-012-2 is only applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers and are not Protection System Components and as such, do not belong in PRC-005. The Protection System definition used within PRC-005 ensures BES reliability through component testing to verify each component's ability to operate. Functional testing is not an activity in PRC-005. The drafting team chose functional testing to emphasize the logic and control functions of RAS. The drafting team contends that functional testing of the non-Protection System RAS components in PRC-012-2 complements the component testing of PRC-005.

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Answer Comment:

Regarding the rationale for Requirement R8--We agree with segmented testing. However, the requirement does not state this and implies an overall test should still be performed.

R8 currently states:

At least once every six-calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components.

Suggest revising to:

At least once every six-calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. This test can be either:

o An end to end test encompassing all components and testing actual functionality

o A segmented test to test all the components by grouping them together into blocks until all parts of the RAS have been tested

Additional information in the Technical Guideline may be required to explain how the six year cycle is measured when allowing segmented testing. Segmented testing can test all components of an RAS every six years, but an individual component could end up being tested once every 10 years. For example, a RAS is designed so that it is comprised of a segment "A", and a segment "B". Segment "A" is tested in year 1, segment "B" is tested in year 5. As per Requirement R8 the RAS has been tested within "six-calendar years." The clocks starts for the next functional test period, and segment "B" is tested in year 1 (one year since its first test), and segment "B" tested in year 5 (nine years since its first test). The RAS was tested within the “six-calendar years”, but segment “B” had a nine year interval. The requirement should be modified to state that all segments shall be tested in the same calendar year.

The RAS-owner should be included in Attachment 3.

Response: Thank you for your comments.

The requirement mandates the overall RAS performance be verified, not that an overall test be conducted. Furthermore, the rationale for Requirement R8 states: “Functional testing may be accomplished with end-to-end testing or a segmented approach.” The drafting team is not specifying the method, only the reliability objective. The drafting team declines to make the suggested change.

A more detailed description of the test intervals is now included in the Rationale and Supplementary Material. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment.

The consolidation of the terms RAS-entity and RAS-owner accomplish your suggestion.

Jared Shakespeare - Peak Reliability - 1 -

Answer Comment:	Peak was unable to locate the “consideration of comments” after the last round of comments posted on the NERC website. The “consideration of comments” are normally posted as part of the Standards Drafting Process to help commenters understand the SDT approach to comments made, and can affect subsequent comments

submitted. Peak encourages NERC to post a “consideration of comments” from all comment periods.

In Attachment 2 under I: Design bullet 6, it states that the effects of future BES modifications… this seems to go outside of the scope of the operating horizon on which the RC is focused.

Response: Thank you for your comments.

The drafting team did not post a response to comments received during the informal posting. The drafting team did consider all of the comments in developing draft 1 of the standard subsequently posted in August.

Attachment 2 is a checklist of reliability-related considerations for the Reliability Coordinator (RC) to review that is based on Attachment 1 information provided by the RAS-entity. The RC is not expected to perform planning analysis but to review the information provided and assess whether future BES modifications have been adequately considered in the RAS design. Furthermore, the RC may request assistance in RAS reviews from other parties such as the PC or regional technical groups if necessary. The drafting team declines to modify this bullet in Attachment 2.

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Answer Comment:

In the Rationale for Requirement R1, the last sentence of the first paragraph is “A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality.” How will “any modification to a RAS beyond the replacement of components” preserve the original functionality? The term “functional modification” requires clarification. Suggest developing a formal definition:

RAS Functional Modification--a change to the resultant action for which a RAS is designed.

Rationale for Requirement R8--We agree with segmented testing. However, the requirement does not state this and implies an overall test should still be performed.

R8 currently states:

"At least once every six-calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components."

Suggest revising to:

"At least once every six-calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. This test can be either:

- An end to end test encompassing all components and testing actual functionality
- A segmented test to test all the components by grouping them together into blocks until all parts of the RAS have been tested"

Additional information in the Technical Guideline may be required to explain how the six year cycle is measured when allowing segmented testing. Segmented testing can test all components of an RAS every six years, but an individual component could end up being tested once every 10 years. For example, a RAS is designed so that it is comprised of a segment “A” and a segment “B”. Segment “A” is tested in year 1, segment “B” is tested in year 5. As per Requirement R8, the RAS has been tested within “six-calendar years.” The clocks starts for the next functional test period and segment “B” is tested in year 1 (one year since its first test) and segment “A” tested in year 5 (nine years since its first test). The RAS was tested within the “six-calendar years”, but segment “A” had a nine year interval. Is this what is intended?

The RAS-owner should be included in Attachment 3.

Response: Thank you for your comments.

The drafting team provided additional clarity for the term “functional modification” in the Rationale. Functional modifications consist of any of the following:

- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement of existing components
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

Several additional examples are included in the Supplementary Material.

The drafting team declines to add the suggested language to the requirement. The objective of the requirement is to test the overall performance of a RAS. This can be accomplished by several methods. The drafting team is not specifying the method, only the reliability objective. The drafting team revised the Rationale and Supplemental Material to provide additional clarity. The drafting team declines to add the suggested language to the requirement: however, the team will include that in the RSAW for PRC-012, Requirement R8.

The drafting team received multiple comments seeking clarification relating to the RAS-entity/owner. The drafting team modified the Applicability section, consolidated the former terms RAS-entity and RAS-owner, and revised the requirements to address these comments.

Mike Smith - Manitoba Hydro - 1 -

Answer Comment:

1. Regarding R1, it is not clear what the term "Functionally Modified" means. "A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality" does not make sense. Does changing some overall scheme's functional logic without replacing any hardware device qualify as "Functional Modified"?

2. R2 should be changed to "Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1, shall, within four-full-calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback including any identified reliability issues to the RAS-entity".

3. R3 should be changed to "Following the review performed pursuant to Requirement R2 and receiving the feedback from the reviewing RC, the RAS-entity shall address each identified issue and obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in service or retiring an existing RAS.

4. R5 requires RAS owner to analyze the performance of every RAS operations. It is not clear how much detail is required in this analysis. For those RAS schemes that operates routinely and regularly as designed, is a declaration of correct operation sufficient analysis?

5. R6 should be changed to "Within six-full-calendar months of identifying or being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)".

Response: Thank you for your comments.

The drafting team provided additional clarity for the term "functional modification" in the Rationale. Functional modifications consist of any of the following:

- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement of existing components
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

Several additional examples are included in the Supplementary Material.

The drafting team agrees and made the suggested change to Requirement R2.

The drafting team agrees and made the suggested change to Requirement R3. Please see the revised requirements and complementary revisions to the measures, rationale boxes, supplemental materials, and Attachments.
The drafting team revised the standard such that Requirement R5 only requires a RAS-entity to provide the results of RAS operational performance analysis to the RC if deficiencies were identified. Please see the revised requirements

and complementary revisions to the measures, rationale boxes, supplemental materials, and Attachments. The RAS-entity must verify that the RAS operated correctly; i.e., that Part 5.1 was satisfied.

The drafting team revised Requirement R6 such that it is in line with your suggestion.

Erika Doot - U.S. Bureau of Reclamation - 5 -

Answer Comment:

Reclamation suggests that the drafting team remove Generator Owners from the applicability section of the standard. Reclamation is unclear on how a Generator Owner could be considered to own all or part of a RAS. Reclamation does not believe that Generator Owners are well situated to analyze system-level RAS impacts or be considered a RAS-entity.

Reclamation believes that a list of elements that may constitute remedial action scheme elements would be helpful for understanding the scope of the standard. Project 2010-05.2, Phase 2 of Protection Systems, defines RAS by listing elements which do not individually constitute RAS. Reclamation is unclear on whether only protection system elements are intended to be considered part of a RAS, or whether elements affected by RAS operation like transmission lines or generators may also be considered RAS elements. Reclamation suggests the inclusion of a guidelines and technical basis section that better defines the parameters of RAS that must be analyzed under R4 and R6, and their relationship to system elements affected by RAS.

Reclamation also suggests that the RAS-entity should be responsible for the R5 analysis of each RAS operation or each failure of a RAS to operate. As written, the requirement would impose duplicative analysis requirements upon RAS owners that would not result in a corresponding reliability benefit. In addition, Reclamation believes that requiring each RAS-owner to conduct an analysis of each RAS operation is unwarranted because owners of one component of a RAS, such as a Generator Owner, would not be in the best position to analyze the RAS operation or its impact on the system. The RAS-entity is the RAS-owner designated to represent all RAS-owners for coordinating the review and approval of a RAS. As outlined in the Technical Justifications, "[t]he purpose of the RAS-entity is to be the single information conduit with each reviewing Reliability Coordinator (RC) for all RAS-owners for each RAS." Reclamation believes the RAS analysis requirement should apply to the entity best situated to analyze the overall RAS operation, the RAS-entity.

Finally, Reclamation suggests that the RAS-entity should be responsible for the R8 functional test of each RAS that is required at least once every six calendar years. A RAS-owner responsible for limited RAS components would not be able to verify the overall RAS performance. The RAS-entity should be responsible for coordinating a functional test with all RAS-owners.

Response: Thank you for your comment.

The drafting team declines to make the suggested change removing the GO. Given the critical nature of RAS, all RAS ownership must be accounted for in order to ensure BES reliability.

The drafting team maintains that the team should not attempt to develop an exhaustive list of RAS components. An exhaustive list of components is not practical given the variety that could be applied in RAS design and implementation. See Item 4a in the Implementation Section of Attachment 1 in the Supplemental Material section for typical RAS components for which redundancy may be considered. The RAS-entity should have a clear understanding of what components were applied to put a RAS into service and which were already present in the system before a RAS was installed. The RC will make the final determination regarding which components should be regarded as RAS components during its review.

The drafting team revised the standard such that Requirement R5 applies to the RAS-entity. The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. As explained in the Technical Justification, each separate RAS-entity is obligated to participate in various activities, as identified by the Requirements to the extent of their ownership. It is not the intent of the drafting team, however, to specify how multiple RAS-entities will coordinate.

Each separate RAS-entity is obligated to participate in various activities, as identified by the Requirements to the extent of their ownership.

Anthony Jablonski - ReliabilityFirst - 10 -

Answer Comment:

1. Applicability Section:

i. ReliabilityFirst believes the “RAS-entity” functional entity under the “Applicability” section may cause issues regarding which entity is responsible for requirements related to the “RAS-entity”. Absent any requirements requiring the RAS-owners to designate and make known the official RAS-entity, it may be difficult to assess compliance on the

RAS-entity. ReliabilityFirst recommends including a new Requirement R1 as follows:

a. R1. For each RAS that is owned by multiple RAS-owners, the RAS-owners shall designate one RAS-entity and inform the Reliability Coordinator(s) and Transmission Planner(s) that coordinates the area(s) where the RAS is located of such designation

2. Requirement R5

i. As written, if there are multiple RAS-owners of a RAS, the expectation is to have multiple analyses performed. ReliabilityFirst believes it would be more appropriate to require the RAS-entity to perform one analysis with coordination of all associated RAS-owners.

3. Requirement R8

i. Requirement R8 requires each RAS-owner to perform a functional test of each RAS. As written, in the case where multiple RAS-owners own a single RAS, multiple tests of the same RAS would be required to be run. ReliabilityFirst believes in cases where a RAS is owned by multiple RAS-owners, a single test should be required by the designated RAS-entity in conjunction with all the RAS-owners.

4. VSL for Requirement R4

i. The time frames for the VSL for Requirement R4 are not all inclusive. For example, the Lower VSL states “less than 61-fullcalendar months” while the moderate VSL states “greater than 61-full-calendar months”. In this example it is unclear which VSL category an entity falls under if they perform the evaluation in 61 months. Listed below is an example of the Lower VSL for the SDT's consideration.

a. The Transmission Planner performed the evaluation in accordance with Requirement R4, but in greater than 60-full-calendar months but less than **[or equal to]** 61-fullcalendar months.

5. VSL for Requirement R7

i. The Lower VSL states that if an entity failed both 7.2 and 7.3 they would fall under the Lower category. ReliabilityFirst questions what VSL an entity would fall under in the scenario where an entity is compliant with 7.2 but not 7.3?

▪ The RAS-owner implemented a CAP (Part 7.1), but failed to update the CAP (Part 7.2) if actions or timetables changed **[OR]** failed to notify one or more of the reviewing Reliability Coordinator(s) (Part 7.3), in accordance with Requirement R7.

Response: Thank you for your comments.

The drafting team disagrees with your proposed changes. The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. As explained in the Technical Justification, each separate RAS-entity is obligated to participate in various activities, as identified by the Requirements to the extent of their ownership. It is not the intent of the drafting team, however, to specify how multiple RAS-entities will coordinate.

The drafting team corrected the VSLs for Requirements R4 and R7.

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Answer Comment:

Requirement R5: The SRC agrees that the RAS entity should evaluate RASs under the circumstances identified in Requirement R5, but would suggest that such entities be required to provide the results of such assessments to their Reliability Coordinator ***and Planning Coordinator***.

Requirement R9: In conjunction with the comment provided under Q2 to replace the TP with the PC, while the SRC agrees that the RC is the appropriate entity to maintain the database, it suggests that the Reliability Coordinator be required to share its database with the applicable Planning Coordinator(s) as some entities may have a need for planned RAS information for modeling and to ensure that appropriate information is shared across the long- and short-term horizons.

Response: Thank you for your comments.

The drafting team revised Requirement R5 such that the RAS-entity provides the results of RAS operational performance analyses that identified any deficiencies to the RC. The RAS-entity would be expected to engage other parties such as its Transmission Planner or Planning Coordinator as necessary to develop a CAP in response to a RAS for which performance issues were identified. The drafting team declines to make the change.

The rationale for Requirement R9 states: The database enables the RC to provide other entities high-level information on existing RAS that can potentially impact operational and/or planning activities of an entity. The drafting team declines to make the suggested change.

Likes:	1	Electric Reliability Council of Texas, Inc., 2, Axson Elizabeth
Dislikes:	0	

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Answer Comment: Entergy supports the SERC PCS comments on this standard.

Response: Please see the drafting team's responses to the referenced comments.

Mark Kenny - Eversource Energy - 3 -

Answer Comment:

Regarding the Applicability Section 4.1.4 for the RAS-entity, who designates the RAS-owner to represent all RAS-owner(s)?

In the Rationale for Requirement R1, last sentence of the first paragraph, "A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality." How will "any modification to a RAS beyond the replacement of components" preserve the original functionality? Functional modification requires clarification. Suggest developing a formal definition:

RAS Functional Modification--a change to the resultant action for which a RAS is designed.

Rationale for Requirement R8--We agree with segmented testing. However, the requirement does not state this and implies an overall test should still be performed.

R8 currently states:At least once every six-calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components.

Suggest revising to: At least once every six-calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. This test can be either:

o An end to end test encompassing all components and testing actual functionality

o A segmented test to test all the components by grouping them together into blocks until all parts of the RAS have been tested

Additional information in the Technical Guideline may be required to explain how the six year cycle is measured when allowing segmented testing. Segmented testing can test all components of an RAS every six years, but an individual component could end up being tested once every 10 years. For example, a RAS is designed so that it is comprised of a segment “A”, and a segment “B”. Segment “A” is tested in year 1, segment “B” is tested in year 5. As per Requirement R8 the RAS has been tested within “six-calendar years.” The clocks starts for the next functional test period, and segment “B” is tested in year 1 (one year since its first test), and segment “B” tested in year 5 (nine years since its first test). The RAS was tested within the “six-calendar years”, but segment “B” had a nine year interval. Is this what is intended?

The RAS-owner should be included in Attachment 3.

R8 and guidance provided in the supplemental material as written appears to overstep the direction provided by the SAR which states that the standard will address maintenance and testing on non-Protection System components of a RAS. Maintenance of Protection Systems installed as a RAS for BES reliability is clearly covered in PRC-005. NPCC is very concerned that there are different timeframes and duplicative testing for RAS components. In particular, the supplemental material provided is very confusing and appears to suggest duplicative testing compared to testing already required in PRC-005. NPCC suggests that all testing requirements for RAS should be contained in one standard.

NPCC suggests deletion of the phase “including any identified deficiencies” in R5 because requirements R5.1 through R5.4 clearly define the necessary level of analysis required by the RAS-owner. Leaving this phrase in will lead to confusion over whether the proper operation of a “composite” RAS is considered a deficiency if one of the two redundant RAS suffer a component failure.

Response: Thank you for your comments.

The drafting team received multiple comments seeking clarification relating to the RAS-entity/owner. The drafting team modified the Applicability section, consolidated the former terms RAS-entity and RAS-owner, and revised the requirements to address these comments.

The drafting team provided additional clarity for the term “functional modification” in the Rationale. Functional modifications consist of any of the following:

- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement of existing components
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

Several additional examples are included in the Supplementary Material.

The drafting team declines to add the suggested language to the requirement. The objective of the requirement is to test the overall performance of a RAS. This can be accomplished by several methods. The drafting team is not specifying the method, only the reliability objective. The drafting team revised the Rationale and Supplemental Material to provide additional clarity. The drafting team declines to add the suggested language to the requirement: however, the team will include that in the RSAW for PRC-012, Requirement R8.

A more detailed description of the test intervals is now included in the Rationale and Supplementary Material. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. The objective of the requirement is to test the overall performance of a RAS. This can be accomplished by several methods. The drafting team is not specifying the method, only the reliability objective. The drafting team revised the Rationale and Supplemental Material to provide additional clarity.

The drafting team regrets any confusion caused by the examples included in the supplemental material. The supplemental material has been revised to better demonstrate the relationship between PRC-005 component testing and PRC-012-2 functional testing. The drafting team disagrees with the addition of functional testing to PRC-005. Requirement 8 in PRC-012-2 is only applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers, that have no applicability within PRC-005. The Protection System definition used within PRC-005 ensures BES reliability through component testing to verify each component's ability to operate. Functional testing is not an activity in PRC-005. The drafting team chose functional testing to emphasize the logic and control functions of RAS and contends that functional testing of the non-Protection System RAS components in PRC-012-2 complements the component testing of PRC-005.   The drafting team revised the standard to allow RAS that have limited impact to have functional testing intervals of up to twelve full calendar years. However, the drafting team contends that the six full calendar year interval is appropriate for the higher impact RAS given the potential negative impact to BES reliability should a RAS operate incorrectly. Existing regional practices include more frequent RAS functional testing than the proposed six full calendar year interval.

Requirements R5.1.1 through 5.1.4 (R5.1 through R5.4 in the previously posted draft of PRC-012-2) state the scope of the RAS operational performance, and therefore any “deficiencies” identified and reported to the RC per Requirement R5.2 are with respect to these. The drafting team contends that if the RAS appropriately triggers for the system conditions for which it was designed, and provides the desired response as designed, that a component failure in one of two redundant RAS would not constitute a deficiency with respect to the operational analysis described in Requirement R5. It would be expected, however, that if such a component failure was identified, the RAS-entity would be incented to repair the failed component as soon as possible to avoid the risk of the RAS failing to operate for a future event. The drafting team declines to make the suggested change.

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Answer Comment: Attachment 1, Section III-Implementation states, “5. Documentation describing the functional testing process.” Dominion recommends deleting this bullet. This information is not necessarily available during the preliminary design phase. The approval of the design is sought prior to detailed engineering. (Planning)

In R5 it states that the RAS owner analyzes the event, but in flow chart it states RAS owner and TP. Dominion suggests that the content in the Flow Chart be consistent with language of the Requirement.

R5 references the timeframe “within 120 calendar days”, however in other areas of the document the time frame is stated to be “within XX calendar months”. Dominion suggests updating the document to reflect the actual timeframe. Dominion also believes consistency is needed and suggests the timeframes reflect "full calendar months” versus “months”.

Response: Thank you for your comments.

Thank you for your comment. The drafting team contends that sufficient information be provided to the RC to allow a proper review including information describing the RAS-entity’s plan for periodic testing. The drafting team declines to make the suggested change.

The drafting team revised the Flowchart.

The drafting team added “mutually agreed upon schedule” to allow more time for the RAS operational analysis to be performed and added the modifier “full” to calendar days. The timeframe of 120 full calendar days is consistent with a similar requirement in PRC-004-5.

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Answer Comment:

1. In addition to RAS-entity's, RAS-owners also have compliance obligations. Yet RAS-owners are not identified in any of the attachments. In addition, the RAS-related equipment of each owner should be identified in one attachment for use by the Reliability Coordinator, the Transmission Planner, and the Compliance Enforcement Authority. Expanding Attachment 3 may be the most efficient way to address these concerns.

2. R5 should be modified by changing this phrase: "…analyze the RAS performance…" to "analyze the performance of its RAS-related equipment." In cases where there are multiple RAS owners, a single RAS-owner cannot analyze the performance of the entire RAS; it can only analyze the performance of its own RAS-related equipment.

Response: Thank you for your comments.

The drafting team received multiple comments seeking clarification relating to the RAS-entity/owner. The drafting team consolidated the former terms RAS-entity and RAS-owner in the Applicability section, revised the requirements and Supplemental Material section of the standard to address these comments.

The drafting team maintains that the team should not attempt to develop an exhaustive list of RAS components. An exhaustive list of components is not practical given the variety that could be applied in RAS design and implementation. See Item 4a in the Implementation Section of Attachment 1 in the Supplemental Material section for typical RAS components for which redundancy may be considered. The RAS-entity should have a clear understanding of what components were applied to put a RAS into service and which were already present in the system before a RAS was installed. The RC will make the final determination regarding which components should be regarded as RAS components during its review.

Each separate RAS-entity is obligated to participate in various activities, as identified by the Requirements to the extent of their ownership. The drafting team revised the Rationale and Supplemental Material to provide additional clarity.

Likes:	4	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla PSEG - PSEG Fossil LLC, 5, Kucey Tim PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
Dislikes:	0	

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Answer Comment:

FirstEnergy would like additional clarification on the phrase "RAS controller" in the second paragraph of the Supplemental Material section in "Applicability", 4.1.4 RAS-entity.

Additionally, FirstEnergy seeks to confirm that if a RAS system operates as planned/designed durnng normal operations then can the data from this actual operation be used to verify/satisfy testing requirements?

Response: Thank you for your comments.

The drafting team received multiple comments seeking clarification relating to the RAS-entity/owner. The drafting team consolidated the former terms RAS-entity and RAS-owner in the Applicability section, revised the requirements and Supplemental Material section of the standard to address these comments.

The drafting team added the language to the measure for Requirement 8 indicating that a correct operation of a RAS segment would qualify as a functional test for that segment. In addition, the team will include that in the RSAW for PRC-012, Requirement R8.

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2

Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1

Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Answer Comment:

Because feeder loading can be changed intentionally, it is frequent to add, substitute, or remove load tripping devices (not distributed relays) in order to maintain the amount of load that is required by a load tripping RAS. Would these changes constitute a RAS functional modification? If so, suggest revising the definition of RAS functional modification. The Attachment 1 procedure that would have to be applied would be overly burdensome.

Regarding the Applicability Section 4.1.4 for the RAS-entity, who designates the RAS-owner to represent all RAS-owner(s)?

In the Rationale for Requirement R1, last sentence of the first paragraph, “A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality.” How will “any modification to a RAS beyond the replacement of components” preserve the original functionality? Functional modification requires clarification. Suggest developing a formal definition:

RAS Functional Modification--a change to the resultant action for which a RAS is designed.

Rationale for Requirement R8--We agree with segmented testing. However, the requirement does not state this and implies an overall test should still be performed.

R8 currently states:

At least once every six-calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components.

Suggest revising to:

At least once every six-calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. This test can be either:

o An end-to-end test encompassing all components and testing actual functionality

o A segmented test to test all the components by grouping them together into blocks until all parts of the RAS have been tested

Additional information in the Technical Guideline may be required to explain how the six year cycle is measured when allowing segmented testing. Segmented testing can test all components of an RAS every six years, but an individual component could end up being tested once every 10 years. For example, a RAS is designed so that it is comprised of a segment “A”, and a segment “B”. Segment “A” is tested in year 1, segment “B” is tested in year 5. As per Requirement R8 the RAS has been tested within “six-calendar years.” The clock starts for the next functional test period, and segment “B” is tested in year 1 (one year since its first test), and segment “A” tested in year 5 (nine years since its first test). The RAS was tested within the “six-calendar years”, but segment “A” had a nine year interval. Is this what is intended? It should be required that all segments be tested in the same calendar year.

The RAS-owner should be included in Attachment 3.

Requirement R8 and guidance provided in the supplemental material as written go beyond the direction stipulated by the SAR which states that the standard will address maintenance and testing on non-Protection System components of a RAS. Maintenance of Protection Systems installed as a RAS for BES reliability is clearly covered in PRC-005. We are very concerned that there are different timeframes and duplicative testing for RAS components. In particular, the supplemental material provided is very confusing and appears to suggest duplicative testing compared to testing already required by PRC-005. Suggest that all testing requirements for RAS should be contained in one standard. The testing time periods should be made consistent with Table 1-1 in PRC-005, specifically 6 years for an unmonitored protection system, and 12 years for an unmonitored microprocessor protection system.

NPCC suggests deletion of the phase “including any identified deficiencies” in R5 because Parts 5.1 through 5.4 clearly define the necessary level of analysis required by the RAS-owner. Leaving this phrase in will lead to confusion over whether the proper operation of a "composite" RAS is considered a deficiency if one of the two redundant RAS suffer a component failure.

In C. Compliance, Section 1.2 Evidence Retention: the RC and TP have not been included. The TO, GO and DP are requested to keep data for requirements that they might not be responsible for.

Response: Thank you for your comments.

The drafting team provided additional clarity for the term "functional modification" in the Rationale. Functional modifications consist of any of the following:

- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement of existing components
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e. addition or removal

Several additional examples are included in the Supplementary Material.

A more detailed description of the test intervals is now included in the Rationale and Supplementary Material. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment.

The drafting team consolidated the former terms RAS-entity and RAS-owner in the Applicability section, revised the requirements and Supplemental Material section of the standard to address these comments.
The functional testing of a RAS to verify its performance is different from the maintenance activities associated with the Protection System Components as detailed in the tables of PRC-005. Requirement 8 of PRC-012-2 is only

applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers and are not Protection System Components and as such, do not belong in PRC-005. The Protection System definition used within PRC-005 ensures BES reliability through component testing to verify each component's ability to operate. Functional testing is not an activity in PRC-005. The drafting team chose functional testing to emphasize the logic and control functions of RAS. The drafting team contends that functional testing of the non-Protection System RAS components in PRC-012-2 complements the component testing of PRC-005.

Requirements R5.1.1 through 5.1.4 (R5.1 through R5.4 in the previously posted draft of PRC-012-2) state the scope of the RAS operational performance, and therefore any "deficiencies" identified and reported to the RC per Requirement R5.2 are with respect to these. The drafting team contends that if the RAS appropriately triggers for the system conditions for which it was designed, and provides the desired response as designed, that a component failure in one of two redundant RAS would not constitute a deficiency with respect to the operational analysis described in Requirement R5. It would be expected, however, that if such a component failure was identified, the RAS-entity would be incented to repair the failed component as soon as possible to avoid the risk of the RAS failing to operate for a future event. The drafting team declines to make the suggested change.

The drafting team declines to add the suggested language to the requirement. The objective of the requirement is to test the overall performance of a RAS. This can be accomplished by several methods. The drafting team is not specifying the method, only the reliability objective. The drafting team revised the Rationale and Supplemental Material to provide additional clarity.

The drafting team regrets any confusion caused by the examples included in the supplemental material. The supplemental material has been revised to better demonstrate the relationship between PRC-005 component testing and PRC-012-2 functional testing. The drafting team disagrees with the addition of functional testing to PRC-005. Requirement 8 in PRC-012-2 is only applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers, that have no applicability within PRC-005. The Protection System definition used within PRC-005 ensures BES reliability through component testing to verify each component's ability to operate. Functional testing is not an activity in PRC-005. The drafting team chose functional testing to emphasize the logic and control functions of RAS and contends that functional testing of the non-Protection System RAS components in PRC-012-2 complements the component testing of PRC-005. The drafting team revised the standard to allow RAS that have limited impact to have functional testing intervals of up to twelve full calendar years. However, the drafting team contends that the six full calendar year interval is appropriate for the higher impact RAS given the potential negative impact to BES reliability should a RAS operate incorrectly. Existing regional practices include more frequent RAS functional testing than the proposed six full calendar year interval.

The Compliance section has been modified to correct the issues you identified.

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Answer Comment:

Tacoma Power recommends that the definition of 'RAS-owner' be limited to functional ownership, as opposed to component ownership. For example, if one company owns a station DC supply, some wiring, and trip coil, but another company owns the control device at the same location, the entity that owns the control device should be a RAS-owner, and the entity that owns the station DC supply, wiring, and trip coil should not be a RAS-owner. Another example would be an entity that owns sensing devices that another entity uses to provide inputs to a relay or PLC that it owns; the entity that owns the sensing devices in this example should not be a RAS-owner. Yet another example is when one entity owns a portion of the communications system; simply owning part of the communications system should not make the entity a RAS-owner.

In the Q & A document, section 9, top of page 6, what if timing is only critical on the order of minutes (e.g., remediation of thermal

	overload). Could replacement of a T1 multiplexor possibly not be considered a RAS functional change in this case? In the Q & A document, section 9, page 6, the example of "replacement of a failed RAS component with an identical component" seems overly exclusive. It is recommended to replace "identical" with "substantially identical." In Requirement R6, why is "six-full calendar months," instead of simply "six calendar months," used? In the Supplemental Material section, page 27, the following sentence has a grammatical/mechanical issue: "A RAS is only allowed to drop non-consequential load or interrupt Firm Transmission Service can do that only if that action is allowed for the Contingency for which it is designed." In the Supplemental Material section, page 28, the following passage does not seem to read well: "These changes could result in inadvertent activation of that output, therefore, tripping too much load and result in violations of Facility Ratings. Alternatively, the RAS might be designed to trip more load than necessary (i.e., "over trip") in order to satisfy single-component-failure requirements. System changes could result in too little load being tripped at affected locations and result in unacceptable BES performance if one of the loads failed to trip." Should the middle sentence be removed? It seems incongruous with the other two sentences. In the Supplemental Material section, page 29, would a CAP be required if equipment fails that is readily replaceable/repairable? Tacoma Power

maintains that CAP's should be required for issues that will require a longer time to address. In general, notification of RAS equipment failures is addressed by other standards.

In the Supplemental Material section, page 30, change "the , the" to "then, the."

Response: Thank you for your comments.

The drafting team disagrees with your proposed change. The drafting team contends that basing RAS ownership on function rather than components could lead to reliability gaps. The RAS-entity owns the facilities, and as the asset owner is responsible for the purchase, design, operation, and testing of a RAS. The drafting team contends your examples strengthen the case for the asset owner to be the responsible entity.

The drafting team modified the example in the Q & A document of replacing a T1 multiplexor to indicate that a resulting change in timing would be a functional modification only if it may be important to the timing of the RAS.

The drafting team added ". . . , or a component that uses the same functionality as the failed component." Other examples were also added to the Supplementary Material.

The "full" allows any fractional month, possibly adding as much as another month.

The drafting team revised the sentence.

The drafting team modified the wording of this section for clarity.
The drafting team contends that even a RAS equipment failure that is readily replaceable/repairable should be documented. Such a CAP may be as simple as an email to the RC to the effect of "Found failed auxiliary relay. Replaced failed auxiliary relay with a spare. Repairs completed on [date]."

The drafting team made the editorial change.

Eric Olson - Transmission Agency of Northern California - 1 -

Answer Comment:

Although neither the Applicability section nor the Requirements of this draft standard distinguish between Protection System components and non-Protection System components of a RAS, the associated supporting information does make such a distinction. For example, the first paragraph of the Background Information section on the Unofficial Comment Form includes the following:

"The maintenance of the Protection System components associated with RAS (PRC-017-1 Remedial Action Scheme Maintenance and Testing) are already addressed in PRC-005. PRC-012-2 addresses the testing of the non-Protection System components associated with RAS/SPS."

NERC's supporting information elsewhere suggests that examples of non-Protection System components include programmable logic controllers, computers, and the control functions of microprocessor relays.

Based on TANC's understanding of NERC's intent for this standard, we suggest that NERC modify the definition of RAS-owner that is provided in the standard's Applicability section to the following.

"RAS-owner - the Transmission Owner, Generator Owner, or Distribution Provider owns all or part of ***the non-Protection System components of*** *a*

RAS" (bold text is added to current proposed definition).

TANC's proposed modified definition would clarify that this standard and its requirements are not applicable to a Transmission Owner, Generator Owner, or Distribution Provider that doesn't own any non-Protection System components of a RAS.

Response: Thank you for your comment.

The drafting team declines to make the suggested change. The drafting team consolidated the former terms RAS-entity and RAS-owner in the Applicability section, revised the requirements and Supplemental Material section of the standard to address these comments.

Leonard Kula - Independent Electricity System Operator - 2 -

Answer Comment:

Requirement R9: In conjunction with our comment under Q2 to replace TP with PC, while we agree that the RC is the appropriate entity to maintain the database, we suggest adding the Planning Coordinator to this requirement for RASs that have been planned and evaluated in the long-term planning timeframe. Some entities may have a need for planned RAS information for modeling.

We recommend that the standard should recognize that all RAS are not equal and therefore should not need the same level of design review (as per R1), performance requirement in case of RAS failure (as per 4.4), and operation analysis (as per R5). We suggest defining two or more "class" or "type" for RAS based on the impact of their misoperation or failure to operate on the system performance. Different class or type of RAS will then have different levels of design, performance and analysis requirements.

R8 and guidance provided in the supplemental material as written appears to overstep the direction provided by the SAR which states that the standard will address maintenance and testing on non-Protection System components of a RAS. Maintenance of Protection Systems installed as a RAS for BES reliability is clearly covered in PRC-005. The IESO is very concerned that there are different timeframes and duplicative testing for RAS components. In particular, the supplemental material provided is very confusing and appears to suggest duplicative testing compared to testing already required in PRC-005. The IESO suggests that all testing requirements for RAS should be contained in one standard. NERC PRC-005 applies to Protection Systems installed as Remedial Action Schemes for BES reliability. As such, all RAS Protective Relays, Communication Systems, Voltage and Current Sensing Devices Providing Inputs to Protective Relays, Control Circuitry, DC Supply, alarms and Automatic Reclosing Components are already included in PRC-005. Lastly, this requirement would force entities to perform testing on local area schemes; yet non-BES components are not subject to maintenance requirements under NERC PRC-005. Typing would be a good mythology to distinguish which RAS schemes should be subject to the strict maintenance requirements.

The IESO suggests deletion of the phase "including any identified deficiencies" in R5 because requirements R5.1 through R5.4 clearly define the necessary level of analysis required by the RAS-owner. Leaving this phrase in will lead to confusion over whether the proper operation of a “composite” RAS is considered a deficiency if one of the two redundant RAS suffer a component failure.

Response: Thank you for your comments.

The drafting team declines to make the suggested change. The drafting team contends that other NERC standards provide adequate methods to assure data sharing among entities with a reliability need.

The drafting team included a provision that RAS can be designated as “limited impact” if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process.

The drafting team regrets any confusion caused by the examples included in the supplemental material. The supplemental material has been revised to better demonstrate the relationship between PRC-005 component testing and PRC-012-2 functional testing. The drafting team disagrees with the addition of functional testing to PRC-005. Requirement 8 in PRC-012-2 is only applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers, that have no applicability within PRC-005. The Protection System definition used within PRC-005 ensures BES reliability through component testing to verify each component’s ability to operate. Functional testing is not an activity in PRC-005. The drafting team chose functional testing to emphasize the logic and control functions of RAS and contends that functional testing of the non-Protection System RAS components in PRC-012-2 complements the component testing of PRC-005. The drafting team revised the standard to allow RAS that have limited impact to have functional testing intervals of up to twelve full calendar years. However, the drafting team contends that the six full calendar year interval is appropriate for the higher impact RAS given the potential negative impact to BES reliability should a RAS operate incorrectly. Existing regional practices include more frequent RAS functional testing than the proposed six full calendar year interval.

Requirements R5.1.1 through 5.1.4 (R5.1 through R5.4 in the previously posted draft of PRC-012-2) state the scope of the RAS operational performance, and therefore any “deficiencies” identified and reported to the RC per Requirement R5.2 are with respect to these. The drafting team contends that if the RAS appropriately triggers for the system conditions for which it was designed, and provides the desired response as designed, that a component failure in one of two redundant RAS would not constitute a deficiency with respect to the operational analysis described in Requirement R5. It would be expected, however, that if such a component failure was identified, the RAS-entity would be incented to repair the failed component as soon as possible to avoid the risk of the RAS failing to operate for a future event. The drafting team declines to make the suggested change.

Richard Vine - California ISO - 2 -

Answer Comment:	The California ISO supports the comments of the ISO/RTO Standards Review Committee

Response: Please see the drafting team’s responses to the referenced comments.

Jamison Cawley - Nebraska Public Power District - 1 -

Answer Comment:	The second version of PRC-005 was intended to include all testing and maintenance requirements from PRC-017, and facilitate the retirement of PRC-017. Requirement 8 of the current draft of this standard (PRC-012-2) includes testing and maintenance requirements related to those found in PRC-017-0. Additionally, Requirement 8 of PRC-012-2 expands

on those found in PRC-017-0 by including non-Protection System components. We feel this requirement should not be included in PRC-012-2, and we request a clear description of the differences of the intended purpose of the proposed PRC-012-2 Requirement 8 and that of PRC-017-0/PRC-005-2. Furthermore, the remaining requirements of PRC-012-2 seem to be primarily focused on system planning, and consideration should be given to moving these to the TPL standard family.

Response: Thank you for your comments.

The functional testing of a RAS to verify its performance is different from the maintenance activities associated with the Protection System Components as detailed in the tables of PRC-005. Requirement 8 of PRC-012-2 is only applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers and are not Protection System Components and as such, do not belong in PRC-005. The Protection System definition used within PRC-005 ensures BES reliability through component testing to verify each component's ability to operate. Functional testing is not an activity in PRC-005. The drafting team chose functional testing to emphasize the logic and control functions of RAS. The drafting team contends that functional testing of the non-Protection System RAS components in PRC-012-2 complements the component testing of PRC-005.

The work performed by the drafting team is in response to the SPCS/SAMS report "Special Protection Systems (SPS) and Remedial Action Schemes (RAS): Assessment of Definition, Regional Practices, and Application of Related Standards". This report recommends "Project 2010-05.2 should consolidate the requirements pertaining to review, assessment, and documentation of SPS into one standard that includes continent-wide procedures for reviewing new or modified SPS, for assessing existing SPS in annual transmission planning assessments, and for periodic comprehensive SPS assessments. The project also should revise requirements pertaining to analysis and reporting of SPS misoperations in a revision of standard PRC-016-0.1." The resulting SAR for aligns with this recommendation and would require the Standard process to re-start with a new SAR. The drafting team maintains this is not necessary and the Reliability objective of the SPCS/SAMS report can be met with PRC-012-2.

Likes:	1	Nebraska Public Power District, 3, Eddleman Tony
Dislikes:	0	

Andrew Gallo - Austin Energy - 6 -

Answer Comment: City of Austin dba Austin Energy suggests the SDT add clarifying language to R8 to account for a RAS-owner who owns only part of a RAS. In doing so, the SDT may need to consider how a partial RAS-owner will be able “to verify the overall RAS performance.”

Response: Thank you for your comment.

The drafting team consolidated the former terms RAS-entity and RAS-owner in the Applicability section, revised the requirements and Supplemental Material section of the standard to address these comments. The drafting team revised the requirement to state that each RAS-entity shall participate in the testing in order to assure accountability for proper testing of each RAS. As explained in the Technical Justification, each separate RAS-entity is obligated to participate in various activities, as identified by the Requirements to the extent of their ownership. It is not the intent of the drafting team, however, to specify how the RAS-entities participate.

Dixie Wells - Lower Colorado River Authority - 5 -

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Answer Comment:

To address existing entity NERC registration in the ERCOT region, “Transmission Planner” should be replaced with “Transmission Planner (in the ERCOT Region this applies to the Planning Authority and /or Reliability Coordinator.)”

R4. Each Transmission Planner (in the ERCOT Region this applies to the Planning Authority and /or Reliability Coordinator) shall perform an evaluation of each RAS within its planning area at least once every 60-full-calendar-months and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Response: Thank you for your comments.

The drafting team revised the requirement. The Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4 and is required to provide the results of the RAS evaluation to each reviewing Reliability Coordinator and each impacted Transmission Planner and RAS-entity. The PC is the functional entity best-suited to perform this evaluation because they have a wide-area planning perspective.

Tony Eddleman - Nebraska Public Power District - 3 -

Answer Comment:

The second version of PRC-005 was intended to include all testing and maintenance requirements from PRC-017, and facilitate the retirement of PRC-017. Requirement 8 of the current draft of this standard (PRC-012-2) includes testing and maintenance requirements related to those found in PRC-017-0. Additionally, Requirement 8 of PRC-012-2 expands on those found in PRC-017-0 by including non-Protection System components. We feel this requirement should not be included in PRC-012-2, and we request a clear description of the differences of the intended purpose of the proposed PRC-012-2 Requirement 8 and that of PRC-017-0/PRC-005-2. Furthermore, the remaining requirements of PRC-012-2 seem to be primarily focused on system planning, and consideration should be given to moving these to the TPL standard family.

Response: Thank you for your comments.

The functional testing of a RAS to verify its performance is different from the maintenance activities associated with the Protection System Components as detailed in the tables of PRC-005. Requirement 8 of PRC-012-2 is only applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers and are not Protection System Components and as such, do not belong in PRC-005. The Protection System definition used within PRC-005 ensures BES reliability through component testing to verify each component's ability to operate. Functional testing is not an activity in PRC-005. The drafting team chose functional testing to emphasize the logic and control functions of RAS. The drafting team contends that functional testing of the non-Protection System RAS components in PRC-012-2 complements the component testing of PRC-005.

Likes:	1	Nebraska Public Power District, 1, Cawley Jamison
Dislikes:	0	

Don Schmit - Nebraska Public Power District - 5 -

Answer Comment:	The second version of PRC-005 was intended to include all testing and maintenance requirements from PRC-017, and facilitate the retirement of PRC-017. Requirement 8 of the current draft of this standard (PRC-012-2) includes testing and maintenance requirements related to those found in PRC-017-0. Additionally, Requirement 8 of PRC-012-2 expands on those found in PRC-017-0 by including non-Protection System components. We feel this requirement should not be included in PRC-012-2, and we request a clear description of the differences of the intended purpose of the proposed PRC-012-2 Requirement 8 and that of PRC-017-0/PRC-005-2. Furthermore, the remaining requirements of PRC-012-2 seem to be primarily focused on system planning, and consideration should be given to moving these to the TPL standard family.

Response: Thank you for your comments.

The functional testing of a RAS to verify its performance is different from the maintenance activities associated with the Protection System Components as detailed in the tables of PRC-005. Requirement 8 of PRC-012-2 is only applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers and are not Protection System Components and as such, do not belong in PRC-005. The Protection System definition used within PRC-005 ensures BES reliability through component testing to verify each component's ability to operate. Functional testing is not an activity in PRC-005. The drafting team chose functional testing to emphasize the logic and control functions of RAS. The drafting team contends that functional testing of the non-Protection System RAS components in PRC-012-2 complements the component testing of PRC-005.

Likes:	1	Nebraska Public Power District, 1, Cawley Jamison
Dislikes:	0	

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Answer Comment: Texas RE seeks clarification on the following:

- If a RAS is implemented to run-back a generator due to a line loading trigger level, is the Generator Owner a RAS-owner by default? Or is it dependent upon the ownership of the components that are used (e.g., protective or auxiliary relays, communication systems, sensing devices,

	station DC, control circuitry, etc.)? • In Requirement R5, is the responsibility associated with the each RAS-owner correct? Should that responsibility be the RAS-entity (in collaboration with all RAS-owners) to avoid multiple analysis activities which may result in conflicting results and/or CAPs? If one RAS-owner finds a deficiency in another owner's portion of the RAS, how is that notification made? • In Requirement R5 there is no notification of a deficiency to a RAS-owner. Is notification considered to be when a RAS-owner recognizes a deficiency in its part of the RAS? R6 references a notification but it is not clear in R5. • Does the SDT consider "arming", whether it signals another party to act or is used in situational awareness, as an integral part of RAS operation? Some RAS designs include an "arming" phase (e.g., A RAS will "arm" if the amperage on line X measure 900 amps. If the amperage measures 920 amps the RAS will activate. In some designs, "arming" may signal action to be taken by another party is needed (e.g. generator runback to level X), and if the action is not taken the RAS may fully activate (e.g. trip generator).) In the Supplemental Material (and somewhat, but not totally, mirrored in the rationale for R5) there is the statement: "A RAS operational performance analysis is intended to: (1) verify RAS operation is consistent with implemented design; or (2) identify RAS performance deficiency(ies) that manifested in the incorrect RAS operation or failure of RAS to operate when expected." Failure of a RAS to arm, if designed to arm, is indicative that the design was improperly implemented.

	• In Requirement R8, which entity responsible for coordinating the functional test for a multi-owner RAS that covers a wide area? The segmented approach referred to in the rationale may cover an individual RAS-owner's trip function or communications, but there needs to be an overall functional test of the logic that arms/disarms/activates the RAS, which may involve multiple RAS-owners. Texas RE recommends changing the requirement language to "RAS-owner, or RAS-entity as mutually agreed by the RAS-owners shall…". Also, a functional test should be required if there is a system change that affects one or more Elements that are monitored or operated as part of a RAS, in order to verify any logic changes. Requirements R1-R3 currently do not address functional testing, only the design. Texas RE recommends R8 indicate "proper operation of RAS" elements and not limit the functional test verification to non-Protection System components. Some Protection System components involved in the proper operation of a RAS may have an extended maintenance intervals and the RAS would not be functionally tested without including Protection System components. Overall RAS performance cannot be attained without functionally testing all aspects of the RAS. Texas RE noticed an inconsistency between the requirement language and the RSAW. The requirement language of Requirement R5 states "Each RAS-owner shall" but the Note to Auditor in the Requirement R5 section of the RSAW indicates that a RAS-entity can provide the analysis. Registered entities are held accountable to the language of the requirement. Introducing the concept of a RAS-entity providing the information adds confusion. If the intent is for both the RAS-Owner and the RAS-entity to be able to analyze RAS performance and provide the results, Texas RE recommends changing the requirement language to

"RAS-owner, or RAS-entity as mutually agreed by the RAS-owners analyze…". Texas RE supports the idea of a RAS-entity doing the analysis.

Additionally, Texas RE recommends a requirement to report the degraded RAS to the RC. Texas RE noticed the referenced Standards/Requirements (i.e., Supplemental Material indicates PRC-001 R6 and TOP-001-2 R5) are either being retired or are not explicit enough to ensure that the reliability of the system is maintained for those who should have situational awareness. This is a perceived gap due to the current steady state of the standards.

Texas RE recommends Attachment 3 include the RAS-owner(s) as well as the RAS-entity. If Requirement R9 is left as "at a minimum", that is all that will be done. Ownership is critical to know because of the responsibilities required in the majority of the Requirements (e.g., How will the TP provide results to owners without knowing all the owners?) The TP does not, generally, know the RAS-owners based on the ownership at the component level.

Response: Thank you for your comments.

The drafting team maintains that the owner of the components in the scenario you describe; e.g., the generator control system would be an owner of the RAS; i.e., a RAS-entity.

The drafting team revised the standard such that Requirement R5 applies to the RAS-entity. The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. As explained in the Technical Justification, each separate RAS-entity is obligated to participate in various activities, as identified by the Requirements to the extent of their ownership. It is not the intent of the drafting team, however, to specify how the RAS-entities participate.

The drafting team revised Requirements R5 and R6.

The drafting team contends that failure of a RAS to arm, if designed to arm, may be indicative that the design was improperly implemented or the RAS did not operate as designed. The event would be handled as a failure to operate, since RAS action should not occur without prior arming, and a CAP developed to resolve the issue pursuant to R6. Any incorrect operation of a RAS, in whole or in part, indicates that the RAS effectiveness and/or coordination has been compromised. The correct operation of a RAS is important for maintaining the reliability and integrity of the BES.

The drafting team revised the requirement to state that each RAS-entity shall participate in the testing in order to assure accountability for proper testing of each RAS. As explained in the Technical Justification, each separate RAS-entity is obligated to participate in various activities, as identified by the Requirements to the extent of their ownership. It is not the intent of the drafting team, however, to specify how the RAS-entities participate. Attachment 1 includes item III. 5 to describe the functional testing process.

The drafting team contends that each owner of a RAS or part of a RAS is a RAS-entity which is responsible for compliance with the requirements of PRC-012. It is not the intent of the drafting team to specify how multiple RAS owners will coordinate. The drafting team believes that it is in the best interest of the BES and the entity to perform a commissioning test, likely to include functional testing when there is a required system change that affects one or more Elements of RAS. The drafting team doesn't dispute the value of functional testing following System changes or RAS logic changes but the standard does not address "commissioning" testing of these changes and contends that is good utility practice but declines to include this in the standard and that adding an additional requirement is unnecessary. The drafting team declines to add an addition requirement to mandate functional testing during RAS changes make the suggested change. The drafting team contends that a "functional test of each RAS to verify the overall RAS performance", as specified in Requirement R8 would include testing of the entire RAS. Requirement R8 specifically requires testing proper operation only of non-Protection System components because Protection System components installed as part of a RAS are already addressed by PRC-005-5.

The drafting team added language to the measure for Requirement 8 indicating that a correct operation of a RAS segment would qualify as a functional test. In addition, the team will include that in the RSAW for PRC-012, Requirement R8. The drafting team's consolidation of RAS-owner and RAS-entity into the single RAS-entity should answer the concern regarding which entity analyzes and reports on RAS operational failures.

The status of a degraded RAS is required to be reported (in Real-time) to the Transmission Operator via PRC-001, Requirement R6, then to the RC via TOP-001-3, Requirement R8. See Phase 2 of Project 2007-06 for the mapping document from PRC-001 to other standards regarding notification of RC by TOP if a deficiency is found during testing. Consequently, it is not necessary to include a similar requirement in this standard.

The drafting team consolidated the former terms RAS-entity and RAS-owner in the Applicability section, revised the requirements and Supplemental Material section of the standard to address these comments.

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Answer Comment:

· Hydro One Networks Inc. recommends that the standard should recognize that all RASs are not equal and therefore, should not be subject to the same level of design review (as per R1), performance requirements in case of RAS failure (as per 4.4), and operation analysis (as per R5). We suggest defining two or more "class" or "type" for RAS based on the impact of their misoperation or failure to operate on the system performance. Different classes or types of RAS will consequently have different levels of design, performance and analysis requirements associated with them. Hydro One Networks Inc. would like to emphasize that in the absence of a means of differentiation (via typing or classes of RAS), utilities will feel compelled to spend significant capital, for little or no material improvement to system reliability.

· Hydro One Networks Inc. believes that requirement R8 and guidance provided in the supplemental material appear to overstep the direction provided by the SAR, which states that the standard will address maintenance and testing on non-Protection System components of a RAS. Maintenance of Protection Systems installed as a RAS for BES reliability is clearly covered in PRC-005. Hydro One Networks Inc. further joins the NPCC with its concern over the different timeframes provided and duplicative testing for RAS components. In particular, the supplemental material provided is very confusing and appears to suggest duplicative testing compared to testing already required in PRC-005. Hydro One Networks Inc. agrees with the NPCC and suggests that all testing requirements for RAS should be contained in one standard. NERC PRC-005 applies to Protection Systems installed as Remedial Action Schemes for BES reliability. As such, all RAS Protective Relays, Communication Systems, Voltage and Current Sensing Devices Providing Inputs to Protective Relays, Control Circuitry, DC Supply, alarms and Automatic Reclosing Components are already included in PRC-005. Lastly, this requirement would force entities to perform testing on local area schemes; yet non-BES components are not subject to maintenance requirements under NERC PRC-005. Typing would be a good mythology to distinguish which RAS schemes should be subject to the strict maintenance requirements.

· Hydro One Networks Inc. also agrees with the NPCC in suggesting the deletion of the phase “including any identified deficiencies” in R5 because requirements R5.1 through R5.4 clearly define the necessary level of analysis required by the RAS-owner. Leaving this phrase in would lead to confusion over whether the proper operation of a "composite" RAS is considered a deficiency if one of the two redundant RAS suffer a component failure.

Response: Thank you for your comments.

The drafting team included a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process.

The functional testing of a RAS to verify its performance is different from the maintenance activities associated with the Protection System Components as detailed in the tables of PRC-005. Requirement 8 of PRC-012-2 is only applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers and are not Protection System Components and as such, do not belong in PRC-005. The Protection System definition used within PRC-005 ensures BES reliability through component testing to verify each component's ability to operate. Functional testing is not an activity in PRC-005. The drafting team chose functional testing to emphasize the logic and control functions of RAS. The drafting team contends that functional testing of the non-Protection System RAS components in PRC-012-2 complements the component testing of PRC-005.

The drafting team included a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process. Limited impact schemes have a twelve full calendar year functional test interval in Requirement R8.

The drafting team regrets any confusion caused by the examples included in the supplemental material. The supplemental material has been revised to better demonstrate the relationship between PRC-005 component testing and PRC-012-2 functional testing. The drafting team disagrees with the addition of functional testing to PRC-005. Requirement 8 in PRC-012-2 is only applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers, that have no applicability within PRC-005. The Protection System definition used within PRC-005 ensures BES reliability through component testing to verify each component's ability to operate. Functional testing is not an activity in PRC-005. The drafting team chose functional testing to emphasize the logic and control functions of RAS and contends that functional testing of the non-Protection System RAS components in PRC-012-2 complements the component testing of PRC-005. The drafting team revised the standard to allow RAS that have limited impact to have functional testing intervals of up to twelve full calendar years. However, the drafting team contends that the six full calendar year interval is appropriate for the higher impact RAS given the potential negative impact to BES reliability should a RAS operate incorrectly. Existing regional practices include more frequent RAS functional testing than the proposed six full calendar year interval.

Requirements R5.1.1 through 5.1.4 (R5.1 through R5.4 in the previously posted draft of PRC-012-2) state the scope of the RAS operational performance, and therefore any "deficiencies" identified and reported to the RC per Requirement R5.2 are with respect to these. The drafting team contends that if the RAS appropriately triggers for the system conditions for which it was designed, and provides the desired response as designed, that a component failure in one of two redundant RAS would not constitute a deficiency with respect to the operational analysis described in Requirement R5. It would be expected, however, that if such a component failure was identified, the RAS-entity would be incented to repair the failed component as soon as possible to avoid the risk of the RAS failing to operate for a future event. The drafting team declines to make the suggested change.

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name:	FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Answer Comment:

The roles and relationships between the RAS-entity and the RAS-owners could be made clearer throughout the standard. Overall, FMPA supports the drafting team's approach, but there have been several comments submitted that should be considered before the standard is approved and would like to see outreach done *before* the next posting of the standard for comment and ballot.

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Answer Comment:

(1) Requirement R9 requires the RC to update its RAS database annually. However, we believe the requirement should be rewritten to require the RC to develop and implement a process to conduct a review of its database and at what frequency. If a RAS-owner has not made any changes to functionality and system conditions and operating configurations are as expected, we feel this requirement is more of an administrative burden falling under Paragraph 81 Data Collection criteria.

(2) We question how a RC is expected to maintain a dated revision history as evidence for Requirement R9 when the context of this requirement is to update a database. We believe the requirement is more of an administrative burden falling under Paragraph 81 Data Collection criteria, and the requirement should be rewritten to require the RC to develop and implement a process to conduct a review of its database and at what frequency.

(3) We believe the evidence retention of this standard should identify retention periods for applicable entities and not limit retention just for TOs, GOs, and DPs.

(4) The VSLs for Requirements R1 and R3 currently have only a Severe VSL identified. We believe the VSL criteria for these requirements could be written on a sliding time scale based on the projected installation or retirement dates of a RAS.

(5) We believe the VSL criteria listed with many requirements is too condensed. We recommend incrementing the criteria for Requirement

R4 by quarters instead of by months. Moreover, we recommend incrementing the criteria for Requirement R5 by months rather than by every ten days. We also recommend incrementing the criteria for Requirements R8 and R9 by quarters rather every thirty days.

(6) We have concerns that the SDT has introduced a new measure of time, the "full-calendar-month." This measure will cause confusion with implementation and during audits. Moreover, there is inconsistent uses of this time measure within the standard. The SDT uses 60-full-calendar-months in R4, but does not use the same measurement in R5 for 120-calendar days and R8 for six-calendar years. Should R5 be four-full-calendar-months and R8 be six-full-calendar-years? The rationale for "full-calendar months" is only specified within the RSAW of this Standard. We feel the SDT should remove the measure of "full-calendar months" and replace it with "calendar months" to be consistent with the other NERC standards.

(7) We thank you for this opportunity to comment on this standard.

Response: Thank you for your comments.

The drafting disagrees that updating a RAS database is an administrative requirement because the database serves as a reliability resource in that the RC can provide other entities high-level information from the database on existing RAS that could potentially impact the operational and/or planning activities of those entities. Readily available software tools allow easy and automatic application of revision dates to documents when updating database documents. Requirement R9 mandates an update frequency of at least every 12 full calendar months.

The drafting team revised the Compliance section of the standard to address this.

The drafting team does not agree that the VSL criteria for Requirements R1 and R3 should be written on a sliding time scale based on the projected installation or retirement dates of a RAS. Projected installation dates are not relevant to the reliability issues. The relevant issue, for both requirements, is to complete a review of the RAS prior to placing a new or functionally modified RAS in-service.

The drafting team declines to make the suggested change to the VSLs.

The drafting team notes that, e.g. PRC-026-1 also uses "full calendar months" terminology. The drafting team declines to make the suggested change.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Comment:

BPA believes R5's reporting to the RC of the correct operation of a RAS is unduly onerous without providing value. BPA analyzes all RAS operations. If we see a scheme that operates too frequently (this is very subjective), we evaluate that scheme to see if there is something that can be done to minimize the number of operations. BPA proposes this be deleted from the requirement.

Response: Thank you for your comment.

The drafting team has modified Requirement R5 to only require reporting of the results of RAS operational analyses when there was an incorrect operation or failure to operate; correct operations do not need to be reported.

End of report

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

Draft 2 of PRC-012-2 corrects the applicability of the fill-in-the-blank standards (PRC-012-1, PRC-013-1, and PRC-014-1) by assigning the requirement responsibilities to the specific users, owners, and operators of the Bulk-Power System, and incorporates the reliability objectives of all the RAS/SPS-related standards. This draft contains nine requirements and measures, the associated rationale boxes and corresponding technical guidelines. There are also three attachments within the draft standard that are incorporated via references in the requirements. This draft of PRC-012-2 is posted for a 45-day formal comment period with a parallel ballot in the last ten days of the comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	February 12, 2014
SAR posted for comment	February 18, 2014
Standards Committee approved the SAR	June 10, 2014
Draft 1 of PRC-012-2 posted for informal comment	April 30 – May 20, 2015
45-day formal comment period with initial ballot	August 20 – October 5, 2015
45-day formal comment period with additional ballot	November 25, 2015 – January 8, 2016

Anticipated Actions	Date
10-day final ballot	March 2016
NERC Board (Board) adoption	May 2016

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Remedial Action Schemes
2. **Number:** PRC-012-2
3. **Purpose:** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Planning Coordinator
     - **4.1.3.** RAS-entity – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS
   - **4.2. Facilities:**
     - **4.2.1.** Remedial Action Schemes (RAS)
5. **Effective Date:** See the Implementation Plan for PRC-012-2.

B. Requirements and Measures

Rationale for Requirement R1: Each Remedial Action Scheme (RAS) is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES). Therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification or retirement; i.e., removal from service must be completed prior to implementation or retirement.

Functional modifications consist of any of the following:

- Changes to System conditions or Contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement of existing components
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

To facilitate a review that promotes reliability, the RAS-entity must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity provide them to the reviewing Reliability Coordinator (RC). The RC (reviewing RC) that coordinates the area where the RAS is located is responsible for the review. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate and submit a single, coordinated Attachment 1 to the reviewing RC. In cases where a RAS crosses one or more RC Area boundaries, each affected RC is responsible for conducting either individual reviews or participating in a coordinated review.

R1. Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, a copy of the Attachment 1 documentation and the dated communications with the reviewing Reliability Coordinator(s) in accordance with Requirement R1.

Rationale for Requirement R2: The RC is the functional entity best suited to perform the RAS review because it has the widest-area operational and reliability perspective of all functional entities and an awareness of reliability issues in any neighboring RC Area. This Wide Area purview facilitates the evaluation of interactions among separate RAS as well as interactions among RAS and other protection and control systems. Review by the RC also minimizes the possibility of a conflict of interest that could exist because of business relationships among the RAS-entity, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC is not expected to possess more information or ability than anticipated by their functional registration as designated by NERC. The RC may request assistance to perform

RAS reviews from other parties such as the PC or regional technical groups; however, the RC will retain the responsibility for compliance with this requirement.

Attachment 2 of this standard is a checklist the RC can use to identify design and implementation aspects of RAS and facilitate consistent reviews for each submitted RAS. The time frame of four full calendar months is consistent with current utility and regional practice; however, flexibility is provided by allowing the RC(s) and RAS-entity(ies) to negotiate a mutually agreed upon schedule for the review.

Note: An RC may need to include this task in its reliability plan(s) for the NERC Regions(s) in which it is located.

R2. Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated reports, checklists, or other documentation detailing the RAS review, and the dated communications with the RAS-entity in accordance with Requirement R2.

Rationale for Requirement R3: The RC review is intended to identify reliability issues that must be resolved before the RAS can be put in-service. Examples of reliability issues include a lack of dependability, security, or coordination.

A specific time period for the RAS-entity to respond to the reviewing RC following identification of any reliability issue(s) is not necessary because the RAS-entity wants to expedite the timely approval and subsequent implementation of the RAS.

R3. Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Acceptable evidence may include, but is not limited to, dated documentation and communications with the reviewing Reliability Coordinator that no reliability issues were identified during the review or that all identified reliability issues were resolved in accordance with Requirement R3.

Rationale for Requirement R4: Requirement R4 mandates that an evaluation of each RAS be performed at least once every sixty full calendar months. The purpose of the periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that, if a RAS single component failure or single component malfunction were to occur, the requirements for BES performance would continue to be satisfied. The periodic evaluation is needed because changes in System topology or operating conditions may change the effectiveness of a RAS or the way it impacts the BES. Requirement R4 also clarifies that the RAS single component failure and single component malfunction tests do not apply to RAS which are determined to be limited impact. A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented after the effective date of this standard will be designated as limited impact or not by the reviewing RC(s) during its review. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact for the purposes of Requirement 4, Parts 4.1.3 and 4.1.4. Requiring a limited impact RAS to meet the single component failure and single component malfunction tests would add complexity to the design with minimal benefit to the reliability of the BES. See Attachment 2 for a description of the limited impact determination by the Reliability Coordinator.

For existing RAS, the initial performance of Requirement R4 must be completed within sixty full calendar months of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within sixty full calendar months of the RAS approval date by the reviewing RC(s). Sixty full calendar months was selected as the maximum time frame between evaluations based on the time frames for similar requirements in Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation can be performed sooner if it is determined that material changes to System topology or System operating conditions could potentially impact the effectiveness or coordination of the RAS. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluation may involve modeling of the interconnected transmission system to assess BES performance. The Planning Coordinator (PC) is the functional entity best suited to perform this evaluation because they have a wide area planning perspective. To promote reliability, the PC is required to provide the results of the evaluation to each impacted Transmission Planner and Planning Coordinator, in addition to each reviewing RC and RAS-entity.

The previous version of this standard (PRC-012-1 Requirement 1, R1.4) states "… 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." Requirement R4 clarifies that the inadvertent operation to be considered would only be that caused by the malfunction of a single RAS component. This allows security features to be designed into the RAS such that inadvertent operation due to a single component malfunction is prevented. Otherwise, consistent with PRC-012-1 Requirement 1, R1.4, the RAS should be designed so that its whole or partial inadvertent operation due to a single component malfunction satisfies the System 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 some other Contingency or System condition not defined in TPL-001-4 (therefore without performance requirements), its inadvertent operation still must meet some minimum System performance requirements. However, instead of referring to the TPL-001-4, Requirement R4 lists the System performance requirements that the inadvertent operation must satisfy. The performance requirements listed (Parts 4.1.3.1 – 4.1.3.5) are the ones that are common to all planning events P0-P7 listed in TPL-001-4.

R4. Each Planning Coordinator, at least once every 60 full calendar months, shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Perform an evaluation of each RAS within its planning area to determine whether:

4.1.1. The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed.

4.1.2. The RAS avoids adverse interactions with other RAS, and protection and control systems.

4.1.3. Except for "limited impact"[1] RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following:

4.1.3.1. The BES shall remain stable.

4.1.3.2. Cascading shall not occur.

4.1.3.3. Applicable Facility Ratings shall not be exceeded.

4.1.3.4. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

4.1.3.5. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

[1] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. See Attachment 2 for a description of the limited impact determination by the Reliability Coordinator. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact for the purposes of Requirement 4, Parts 4.1.3 and 4.1.4.

4.1.4. Except for limited impact RAS, 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 is designed.

4.2. Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.

M4. Acceptable evidence may include, but is not limited to, dated reports or other documentation of the analyses comprising the evaluation(s) of each RAS and dated communications with the RAS-entity(ies), Transmission Planner(s), Planning Coordinator(s), and the reviewing Reliability Coordinator(s) in accordance with Requirement R4.

Rationale for Requirement R5: The correct operation of a RAS is important for maintaining the reliability and integrity of the BES. Any incorrect operation of a RAS indicates that the RAS effectiveness and/or coordination has been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: 1) verify RAS operation was consistent with the implemented design; or 2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120 full calendar day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation. To promote reliability, each RAS-entity is required to provide the results of RAS operational performance analyses that identified any deficiencies to its reviewing RC(s).

RAS-entities may need to collaborate with their associated Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation was triggered correctly (Part 5.1.1), responded as designed (Part 5.1.2), and that the resulting BES response (Parts 5.1.3 and 5.1.4) was consistent with the intended functionality and design of the RAS. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate on the operational performance analysis.

R5. Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Participate in analyzing the RAS operational performance to determine whether:

5.1.1. The System events and/or conditions appropriately triggered the RAS.

5.1.2. The RAS responded as designed.

5.1.3. The RAS was effective in mitigating BES performance issues it was designed to address.

5.1.4. The RAS operation resulted in any unintended or adverse BES response.

5.2. Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).

M5. Acceptable evidence may include, but is not limited to, dated documentation detailing the results of the RAS operational performance analysis and dated communications with the reviewing Reliability Coordinator(s) in accordance with Requirement R5.

Rationale for Requirement R6: Deficiencies identified in the periodic RAS evaluation conducted by the PC pursuant to Requirement R4, in the operational performance analysis conducted by the RAS-entity pursuant to Requirement R5, or in the functional test performed by the RAS-entity pursuant to Requirement R8, potentially pose a reliability risk to the BES. To mitigate these potential reliability risks, Requirement R6 mandates that each RAS-entity develop a Corrective Action Plan (CAP) to address the identified deficiency. The CAP contains the mitigation actions and associated timetable necessary to remedy the specific deficiency. The RAS-entity may request assistance with CAP development from other parties such as its Transmission Planner or Planning Coordinator; however, the RAS-entity has the responsibility for compliance with this requirement.

If the CAP requires that a functional change be made to a RAS, the RAS-entity will need to submit information identified in Attachment 1 to the reviewing RC(s) prior to placing RAS modifications in-service per Requirement R1.

Depending on the complexity of the identified deficiency(ies), development of a CAP may require studies, and other engineering or consulting work. A maximum time frame of six full calendar months is specified for RAS-entity collaboration on the CAP development.

R6. Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

- Being notified of a deficiency in its RAS pursuant to Requirement R4, or
- Notifying the Reliability Coordinator pursuant to Requirements R5, or
- Identifying a deficiency in its RAS pursuant to Requirement R8.

M6. Acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each reviewing Reliability Coordinator and each RAS-entity in accordance with Requirement R6.

Rationale for Requirement R7: Requirement R7 mandates each RAS-entity implement a CAP (developed in Requirement R6) that mitigates the deficiencies identified in Requirements R4, R5, or R8. By definition, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem." The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. Each reviewing Reliability Coordinator must be notified if CAP actions or timetables change, and when the CAP is completed.

R7. Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

7.1. Implement the CAP.

7.2. Update the CAP if actions or timetables change.

7.3. Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

M7. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, and communication with the reviewing Reliability Coordinator(s) that documents the implementation, updating, or completion of a CAP in accordance with Requirement R7.

Rationale for Requirement R8: Due to the wide variety of RAS designs and implementations, and the potential for impacting BES reliability, it is important that periodic functional testing of a RAS be performed. A functional test provides an overall confirmation of the RAS to operate as designed and verifies the proper operation of the non-Protection System (control) components of a RAS that are not addressed in PRC-005. Protection System components that are part of a RAS are maintained in accordance with PRC-005.

The six or twelve full calendar year test interval, which begins on the effective date of the standard pursuant to the PRC-012-2 implementation plan, is a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS. Extending to longer intervals increases the reliability risk to the BES posed by an undiscovered latent failure that could cause an incorrect operation or failure of the RAS. The RAS-entity is in the best position to determine the testing procedure and schedule due to its overall knowledge of the RAS design, installation, and functionality. Functional testing may be accomplished with end-to-end testing or a segmented approach. For segmented testing, each segment of a RAS must be tested. Overlapping segments can be tested individually negating the need for complex maintenance schedules and outages.

The maximum allowable interval between functional tests is six full calendar years for RAS that are not designated as limited impact RAS and twelve full calendar years for RAS that are designated as limited impact RAS. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. A correct operation of a RAS qualifies as a functional test for those RAS segments which operate (documentation for compliance with Requirement R5 Part 5.1). If an event causes a partial operation of a RAS, the segments without an operation will require a separate functional test within the maximum interval with the starting date determined by the previous successful test of the segments that did not operate.

R8. Each RAS-entity shall participate in performing a functional test of each of its RAS to verify the overall RAS performance and the proper operation of non-Protection System components: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

- At least once every six full calendar years for all RAS not designated as limited impact, or
- At least once every twelve full calendar years for all RAS designated as limited impact

M8. Acceptable evidence may include, but is not limited to, dated documentation detailing the RAS operational performance analysis for a correct RAS segment or an end-to-end operation (Measure M5 documentation), or dated documentation demonstrating that a functional test of each RAS segment or an end-to-end test was performed in accordance with Requirement R8.

Rationale for Requirement R9: The RAS database is a comprehensive record of all RAS existing in a Reliability Coordinator Area. The database enables the RC to provide other entities high-level information on existing RAS that could potentially impact the operational and/or planning activities of that entity. Attachment 3 lists the minimum information required for the RAS database, which includes a summary of the RAS initiating conditions, corrective actions, and System issues being mitigated. This information allows an entity to evaluate the reliability need for requesting more detailed information from the RAS-entities identified in the database contact information. The RC is the appropriate entity to maintain the database because the RC receives the required database information when a new or modified RAS is submitted for review. The twelve full calendar month time frame is aligned with industry practice and allows sufficient time for the RC to collect the appropriate information from RAS-entities and update the RAS database.

R9. Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once every twelve full calendar months. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M9. Acceptable evidence may include, but is not limited to, dated spreadsheets, database reports, or other documentation demonstrating a RAS database was updated in accordance with Requirement R9.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The RAS-entity (Transmission Owner, Generator Owner, and Distribution Provider) shall each keep data or evidence to show compliance with Requirements R1, R3, R5, R6, R7, and R8, and Measures M1, M3, M5, M6, M7, and M8 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Reliability Coordinator shall each keep data or evidence to show compliance with Requirements R2 and R9, and Measures M2 and M9 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Planning Coordinator shall each keep data or evidence to show compliance with Requirement R4 and Measure M4 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a RAS-entity (Transmission Owner, Generator Owner or Distribution Provider), Reliability Coordinator, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The RAS-entity failed to provide the information identified in Attachment 1 to each Reliability Coordinator prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R1.
R2.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90 full calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in accordance with Requirement R2.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	N/A	N/A	N/A	The RAS-entity failed to resolve identified reliability issue(s) to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R3.
R4.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but in greater than 60 full calendar months but less than or equal to 61 full calendar months.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but in greater than 61 full calendar months but less than or equal to 62 full-calendar months.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but in greater than 62 full calendar months but less than or equal to 63 full calendar months. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate one of the Parts 4.1.1 through 4.1.4.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but in greater than 63 full calendar months. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate two or more of the Parts 4.1.1 through 4.1.4. OR

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to provide the results to one or more of the receiving entities listed in Part 4.2. OR The Planning Coordinator failed to perform the evaluation in accordance with Requirement R4.
R5.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by less than or equal to 10 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address one of the Parts 5.1.1 through 5.1.4.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address two or more of the Parts 5.1.1 through 5.1.4.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to provide the results (Part 5.2) to one or more of the reviewing Reliability Coordinator(s). OR The RAS-entity failed to perform the analysis in accordance with Requirement R5.
R6.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30 full calendar days. OR The RAS-entity developed a Corrective Action Plan but failed to submit it to one or

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				more of its reviewing Reliability Coordinator(s) in accordance with Requirement R6. OR The RAS-entity failed to develop a Corrective Action Plan in accordance with Requirement R6.
R7.	The RAS-entity implemented a CAP in accordance with Requirement R7, Part 7.1, but failed to update the CAP (Part 7.2) if actions or timetables changed, or failed to notify (Part 7.3) each of the reviewing Reliability Coordinator(s) of the updated CAP or completion of the CAP.	N/A	N/A	The RAS-entity failed to implement a CAP in accordance with Requirement R7, Part 7.1.
R8.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by less than or equal to 30 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 30 full calendar days	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 60 full calendar days	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 90 full calendar days.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		but less than or equal to 60 full calendar days.	but less than or equal to 90 full calendar days.	OR The RAS-entity failed to perform the functional test for a RAS as specified in Requirement R8.
R9.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90 full calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

D. Regional Variances

None.

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
1		Adopted by NERC Board of Trustees	New

Attachment 1
Supporting Documentation for RAS Review

The following checklist identifies important Remedial Action Scheme (RAS) information for each new or functionally modified[2] RAS that the RAS-entity must document and provide to the reviewing Reliability Coordinator(s) (RC). If an item on this list does not apply to a specific RAS, a response of “Not Applicable” for that item is appropriate. When RAS are submitted for functional modification review and approval, only the proposed modifications to that RAS require review; however, the RAS-entity must provide a summary of the existing functionality. The RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS. Additional entities (without decision authority) may be part of the RAS review process at the request of the RC.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.
2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.
3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP.
4. Data to populate the RAS database:
    a. RAS name.
    b. Each RAS-entity and contact information.
    c. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
    d. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
    e. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
    f. Action(s) to be taken by the RAS.

[2] Functionally Modified: Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement of existing components
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

g. Identification of limited impact[3] RAS.

h. Any additional explanation relevant to high-level understanding of the RAS.

II. Functional Description and Transmission Planning Information

1. Contingencies and System conditions that the RAS is intended to remedy.
2. The action(s) to be taken by the RAS in response to disturbance conditions.
3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and the date those technical studies were performed.
4. Information regarding any future System plans that will impact the RAS.
5. RAS-entity proposed designation as limited impact or not.
6. Documentation describing the System performance resulting from the possible inadvertent operation of the RAS, except for limited impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be limited impact must satisfy all of the following:
   a. The BES shall remain stable.
   b. Cascading shall not occur.
   c. Applicable Facility Ratings shall not be exceeded.
   d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.
   e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.
7. An evaluation indicating that the RAS settings and operation avoid adverse interactions with other RAS, and protection and control systems.
8. Identification of other affected RCs.

[3] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. See Attachment 2 for a description of the limited impact determination by the Reliability Coordinator. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.

III. Implementation

1. Documentation describing the applicable equipment used for detection, dc supply, communications, transfer trip, control actions, logic processing, and monitoring.
2. Information on detection logic and settings/parameters that control the operation of the RAS.
3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in-service or is being maintained.
4. Documentation describing the System performance resulting from a single component failure in the RAS, except for limited impact RAS, when the RAS is intended to operate. A single component failure in a RAS not determined to be limited impact must 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 is designed. The documentation should describe or illustrate how the design achieves this objective.
5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies RAS information that the RAS-entity shall document and provide to each reviewing RC.

1. Information necessary to ensure that the RC is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of applicable technical studies and technical justifications upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

Attachment 2
Reliability Coordinator RAS Review Checklist

The following checklist identifies reliability-related considerations for the Reliability Coordinator (RC) to review and verify for each new or functionally modified[4] Remedial Action Scheme (RAS). The RC review is not limited to the checklist items and the RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS. If a checklist item is not relevant to a particular RAS, it should be noted as “Not Applicable.” If reliability considerations are identified during the review, the considerations and the proposed resolutions should be documented with the remaining applicable Attachment 2 items.

I. Design

1. The RAS actions satisfy performance objectives for the scope of events and conditions that the RAS is intended to mitigate.
2. The RAS arming conditions, if applicable, are appropriate to its System performance objectives.
3. The RAS avoids adverse interactions with other RAS, and protection and control systems.
4. The effects of RAS incorrect operation, including inadvertent operation and failure to operate, have been identified.
5. Determination whether or not the RAS is “limited impact.[5]” A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.
6. Except for limited impact RAS as determined by the RC, the possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following:
    a. The BES shall remain stable.
    b. Cascading shall not occur.
    c. Applicable Facility Ratings shall not be exceeded.

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[4] Functionally Modified: Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement of existing components
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

[5] A RAS designated as “limited impact” cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.

d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

7. The effects of future BES modifications on the design and operation of the RAS have been identified, where applicable.

II. Implementation

1. The implementation of RAS logic appropriately correlates desired actions (outputs) with events and conditions (inputs).
2. The timing of RAS action(s) is appropriate to its BES performance objectives.
3. Except for limited impact RAS as determined by the RC, a single component failure in a RAS does not prevent the BES from meeting the same performance requirements as those required for the events and conditions for which the RAS is designed.
4. The RAS design facilitates periodic testing and maintenance.
5. The mechanism or procedure by which the RAS is armed is clearly described, and is appropriate for reliable arming and operation of the RAS for the conditions and events for which it is designed to operate.

III. RAS Retirement

RAS retirement reviews should assure that there is adequate justification for why a RAS is no longer needed.

Attachment 3
Database Information

1. RAS name.
2. Each RAS-entity and contact information.
3. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
5. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
6. Action(s) to be taken by the RAS.
7. Identification of limited impact[6] RAS.
8. Any additional explanation relevant to high-level understanding of the RAS.

[6] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.

Technical Justifications for Requirements

Applicability

4.1.1 Reliability Coordinator

The Reliability Coordinator (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. The Wide-Area purview 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, Planning Coordinator, Transmission Planner, or other entities 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.

4.1.2 Planning Coordinator

The Planning Coordinator (PC) is the best-suited functional entity to perform the RAS evaluation 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, similar to the planning analyses performed by PCs.

4.1.3 RAS-entity

The RAS-entity is any Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If all of the RAS (RAS components) have a single owner, then that RAS-entity has sole responsibility for all the activities assigned within the standard to the RAS-entity. If the RAS (RAS components) have more than one owner, then each separate RAS component owner is a RAS-entity and is obligated to participate in various activities identified by the Requirements.

The standard does not stipulate particular compliance methods. RAS-entities have the option of collaborating to fulfill their responsibilities for each applicable requirement. Such collaboration and coordination may promote efficiency in achieving the reliability objectives of the requirements; however, the individual RAS-entity must be able to demonstrate its participation for compliance. As an example, the individual RAS-entities could collaborate to produce and submit a single, coordinated Attachment 1 to the reviewing RC pursuant to Requirement R1 to initiate the RAS review process.

Requirement R1

Each RAS is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES); therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification, or retirement (removal from service) must be completed prior to implementation.

Functional modifications consists of any of the following:

- Changes to System conditions or Contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement of existing components
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

An example indicating the limits of an in-kind replacement of a RAS component is the replacement of one relay (or other device) with a relay (or other device) that uses similar functions. For instance, if a RAS included a CO-11 relay which was replaced by an IAC-53 relay, that would be an in-kind replacement. If the CO-11 relay were replaced by a microprocessor SEL-451 relay that used only the same functions as the original CO-11 relay, that would also be an in-kind replacement; however, if the SEL-451 relay was used to add new logic to what the CO-11 relay had provided, then the replacement relay would be a functional modification.

Changes to RAS pickup levels that require no other scheme changes are not considered a functional modification. For example, System conditions require a RAS to be armed when the combined flow on two lines exceeds 500 MW. If a periodic evaluation pursuant to Requirement R4, or other assessment, indicates that the arming level should be reduced to 450 MW without requiring any other RAS changes that would not be a functional modification. Similarly, if a RAS is designed to shed load to reduce loading on a particular line below 1000 amps, then a change in the load shedding trigger from 1000 amps to 1100 amps would not be a functional modification.

Another example illustrates a case where a System change may result in a RAS functional change. Assume that a generation center is connected to a load center through two transmission lines. The lines are not rated to accommodate full plant output if one line is out of service, so a RAS monitors the status of both lines and trips or ramps down the generation to a safe level following loss of either line. Later, one of the lines is tapped to serve additional load. The System that the RAS impacts now includes three lines, loss of any of which is likely to still require generation reduction. The modified RAS will need to monitor all three lines (add two line terminal status inputs to the RAS) and the logic to recognize the specific line outages would change, while the generation reduction (RAS output) requirement may or may not change, depending on which line is out of service. These required RAS changes would be a functional modification.

Any functional modification to a RAS will need to be reviewed and approved through the process described in Requirements R1, R2, and R3. The need for such functional modifications may be identified in several ways including but not limited to the Planning evaluations pursuant to R4, incorrect operations pursuant to R5, a test failure pursuant to R8, or Planning assessments related to future additions or modifications of other facilities.

To facilitate a review that promotes reliability, the RAS-entity(ies) must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity(ies) provide them to the reviewing Reliability Coordinator (RC). The RC that coordinates the area where the RAS is located is responsible for the review. In cases where a RAS crosses multiple RC Area boundaries, each affected RC is responsible for conducting either individual reviews or a coordinated review.

Requirement R1 does not specify how far in advance of implementation the RAS-entity(ies) must provide Attachment 1 data to the reviewing RC. The information will need to be submitted early enough to allow RC review in the allotted time pursuant to Requirement R2, including resolution of any reliability issues that might be identified, in order to obtain approval of the reviewing RC. Expeditious submittal of this information is in the interest of each RAS-entity to effect a timely implementation.

Requirement R2

Requirement R2 mandates that the RC perform reviews of all proposed new RAS and existing RAS proposed for functional modification, or retirement (removal from service) in its RC Area.

RAS are unique and customized assemblages of protection and control equipment. As such, they have a potential to introduce reliability risks to the BES, if not carefully planned, designed, and installed. A RAS may be installed to address a reliability issue, or achieve an economic or operational advantage, and could introduce reliability risks that might not be apparent to a RAS-entity(ies). An independent review by a multi-disciplinary panel of subject matter experts with planning, operations, protection, telecommunications, and equipment expertise is an effective means of identifying risks and recommending RAS modifications when necessary.

The RC is the functional entity best suited to perform the RAS reviews because it has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. This Wide Area purview facilitates the evaluation of interactions among separate RAS as well as interactions among the 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, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC may request assistance in RAS reviews from other parties such as the PC(s) or regional technical groups (e.g., Regional Entities); however, the RC retains responsibility for compliance with the requirement. It is recognized that the RC does not possesses more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not contain compliance requirements. If Reliability Standards address functions that are not described in the model, the Reliability Standard requirements take precedence over the Functional Model. For further reference, please see the Introduction section of NERC’s Reliability Functional Model, Version 5, November 2009.

Attachment 2 of this standard is a checklist for assisting the RC in identifying design and implementation aspects of a RAS, and for facilitating consistent reviews of each RAS submitted for review. The time frame of four full calendar months is consistent with current utility practice; however, flexibility is provided by allowing the parties to negotiate a different schedule for the review. Note, an RC may need to include this task in its reliability plan(s) for the NERC Region(s) in which it is located.

Requirement R3

Requirement R3 mandates that each RAS-entity resolve all reliability issues (pertaining to its RAS) identified during the RAS review by the reviewing Reliability Coordinators. Examples of reliability issues include a lack of dependability, security, or coordination. RC approval of a RAS is considered to be obtained when the reviewing RC's feedback to each RAS-entity indicates that either no reliability issues were identified during the review or all identified reliability issues were resolved to the RC's satisfaction.

Dependability is a component of reliability that is the measure of certainty of a device to operate when required. If a RAS is installed to meet performance requirements of NERC Reliability Standards, a failure of the RAS to operate when intended would put the System at risk of violating NERC Reliability Standards if specified Contingency(ies) or System conditions occur. This risk is mitigated by designing the RAS so that it will accomplish the intended purpose while experiencing a single RAS component failure. This is often accomplished through redundancy. Other strategies for providing dependability include "over-tripping" load or generation, or alternative automatic backup schemes.

Security is a component of reliability that is the measure of certainty of a device to not operate inadvertently. False or inadvertent operation of a RAS results in taking a programmed action without the appropriate arming conditions, occurrence of specified Contingency(ies), or System conditions expected to trigger the RAS action. Typical RAS actions include shedding load or generation or re-configuring the System. Such actions, if inadvertently taken, are undesirable and may put the System in a less secure state. Worst case impacts from inadvertent operation often occur if all programmed RAS actions occur. If the System performance still satisfies PRC-012-2 Requirement R4, Part 4.3, no additional mitigation is required. Security enhancements to the RAS design, such as voting schemes, are acceptable mitigations against inadvertent operations.

Any reliability issue identified during the review must be resolved before implementing the RAS to avoid placing the System at unacceptable risk. The RAS-entity or the reviewing RC(s) may have alternative ideas or methods available to resolve the issue(s). In either case, the concern needs to be resolved in deference to reliability, and the RC has the final decision.

A specific time period for the RAS-entity to respond to the RC(s) review is not necessary because an expeditious response is in the interest of each RAS-entity to effect a timely implementation.

Requirement R4

Requirement R4 mandates that an evaluation of each RAS be performed at least once every 60 full calendar months. The purpose of a periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that requirements for BES performance following inadvertent RAS operation and single component failure continue to be satisfied. A periodic evaluation is required because changes in System topology or operating conditions may change the effectiveness of a RAS or the way it interacts with and impacts the

BES. Requirement R4 also clarifies that the RAS single component failure and inadvertent operation tests do not apply to RAS which are determined to be limited impact. Requiring a limited impact RAS to meet the single component failure and inadvertent operation tests would just add complexity to the design with little or no improvement in the reliability of the BES.

For existing RAS, the initial performance of Requirement R4 must be completed within sixty full calendar months of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within sixty full calendar months of the RAS approval date by the reviewing RC(s). Sixty full calendar months was selected as the maximum time frame between evaluations based on the time frames for similar requirements in Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation can be performed sooner if it is determined that material changes to System topology or System operating conditions could potentially impact the effectiveness or coordination of the RAS. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluations (Requirement R4, Parts 4.1.1 through 4.1.4) are planning analyses that may involve modeling of the interconnected transmission system to assess BES performance. The PC is the functional entity best suited to perform the analyses because they have a wide-area planning perspective. To promote reliability, the PC is required to provide the results of the evaluation to each RAS-entity and reviewing RC, as well as each impacted Planning Coordinator and Transmission Planner.

The intent of Requirement R4, Part 4.1.3 is to require that the possible inadvertent operation of the RAS (other than limited impact RAS), caused by the malfunction of a single component of the RAS, meet the same System performance requirements as those required for the Contingency(ies) or System conditions for which it is designed. If the RAS is designed to meet one of the planning events (P0-P7) in TPL-001-4, the possible inadvertent operation of the RAS must meet the same performance requirements listed in the standard for that planning event. The requirement clarifies that the inadvertent operation to be considered is only that caused by the malfunction of a single RAS component. This allows features to be designed into the RAS to improve security, such that inadvertent operation due to malfunction of a single component is prevented; otherwise, the RAS inadvertent operation must satisfy Requirement R4, Part 4.1.3.

The intent of Requirement R4, Part 4.1.3 is also to require that the possible inadvertent operation of the RAS (other than limited impact RAS) installed for an extreme event in TPL-001-4 or for some other Contingency or System conditions not defined in TPL-001-4 (therefore without performance requirements), meet the minimum System performance requirements of Category P7 in Table 1 of NERC Reliability Standard TPL-001-4. However, instead of referring to the TPL standard, the requirement lists the System performance requirements that a potential inadvertent operation must satisfy. The performance requirements listed (Requirement R4, Parts 4.1.3.1 – 4.1.3.5) are the ones that are common to all planning events (P0-P7) listed in TPL-001-4.

With reference to Requirement 4, Part 4.1.3, note that the only differences in performance requirements among the TPL (P0-P7) events (not common to all of them) concern Non-

Consequential Load Loss and interruption of Firm Transmission Service. It is not necessary for Requirement R4, Part 4.1.3 to specify performance requirements related to these areas because a RAS is only allowed to drop non-consequential load or interrupt Firm Transmission Service if that action is allowed for the Contingency for which it is designed. Therefore, the inadvertent operation should automatically meet Non-Consequential Load Loss or interrupting Firm Transmission Service performance requirements for the Contingency(ies) for which it was designed.

Part 4.1.4 requires that a single component failure in the RAS (other than limited impact 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 is designed. This analysis is needed to ensure that changing System conditions do not result in the single component failure requirement not being met.

Requirements for inadvertent RAS operation (Requirement R4, Part 4.1.3) and single component failure (Requirement R4, Part 4.1.4) are reviewed by the reviewing RC(s) before a new or functionally modified RAS is placed in-service, and are typically satisfied by specific design considerations. Although the scope of the periodic evaluation does not include a new design review, it is possible that a design which previously satisfied requirements for inadvertent RAS operation and single component failure may fail to satisfy these requirements at a later time, and must be evaluated with respect to the current System. For example, if the actions of a particular RAS include tripping load, load growth could occur over time that impacts the amount of load to be tripped. These changes could result in tripping too much load upon inadvertent operation and result in violations of Facility Ratings. Alternatively, the RAS might be designed to trip more load than necessary (i.e., “over trip”) in order to satisfy single component failure requirements. System changes could result in too little load being tripped and unacceptable BES performance if one of the loads failed to trip.

Requirement R5

The correct operation of a RAS is important to maintain the reliability and integrity of the BES. Any incorrect operation of a RAS indicates the RAS effectiveness and/or coordination may have been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: (1) verify RAS operation is consistent with implemented design; or (2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120 full calendar day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation; however, flexibility is provided by allowing the parties to negotiate a different schedule for the analysis. To promote reliability, the RAS-entity(s) is required to provide the results of RAS operational performance analyses to its reviewing RC(s).

The RAS-entity(ies) may need to collaborate with its associated Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation was triggered correctly (Part 5.1.1), responded as designed (Part 5.1.2), and that the resulting BES response (Parts 5.1.3 and 5.1.4) was consistent with the intended functionality and design of the RAS. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate on the operational performance analysis.

Requirement R6

RAS deficiencies potentially pose a reliability risk to the BES. RAS deficiencies may be identified in the periodic RAS evaluation conducted by the PC in Requirement R4, in the operational analysis conducted by the RAS-entity in Requirement R5, or in the functional test performed by the RAS-entity(ies) in Requirement R8. To mitigate potential reliability risks, Requirement R6 mandates that each RAS-entity participate in developing a CAP that establishes the mitigation actions and timetable necessary to address the deficiency.

The RAS-entity(ies) that owns the RAS components, is responsible for the RAS equipment, and is in the best position to develop the timelines and perform the necessary work to correct RAS deficiencies. If necessary, the RAS-entity(ies) may request assistance with development of the CAP from other parties such as its Transmission Planner or Planning Coordinator; however, the RAS-entity has the responsibility for compliance with this requirement.

A CAP may require functional changes be made to a RAS. In this case, Attachment 1 information must be submitted to the reviewing RC(s), an RC review must be performed to obtain RC approval before the RAS-entity can place RAS modifications in-service, per Requirements R1, R2, and R3.

Depending on the complexity of the issues, development of a CAP may require study, engineering or consulting work. A timeframe of six full calendar months is allotted to allow enough time for RAS-entity collaboration on the CAP development, while ensuring that deficiencies are addressed in a reasonable time. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the RAS deficiency is resolved. The possibility of such operating restrictions will incent the RAS-entity to resolve the issue as quickly as possible.

The following are example situations of when a CAP is required:

- A determination after a RAS operation/non-operation investigation that the RAS did not meet performance expectations or did not operate as designed.
- Periodic planning assessment reveals RAS changes are necessary to correct performance or coordination issues.
- Equipment failures.
- Functional testing identifies that a RAS is not operating as designed.

Requirement R7

Requirement R7 mandates that each RAS-entity implement its CAP developed in Requirement R6 which mitigates the deficiencies identified in Requirements R4, R5, or R8. By definition, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem."

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. If the CAP is changed, the RAS-entity must notify the reviewing Reliability Coordinator(s). The RAS-entity must also notify the Reliability Coordinator(s) when the CAP has been completed.

The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions will incent the RAS-entity to complete the CAP as quickly as possible.

Requirement R8

The reliability objective of Requirement R8 is to test the non-Protection System components of a RAS (controllers such as programmable logic controllers (PLCs)) and to verify the overall performance of the RAS through functional testing. Functional tests validate RAS operation by ensuring System states are detected and processed, and that actions taken by the controls are correct and occur within the expected time using the in-service settings and logic. Functional testing is aimed at assuring overall RAS performance and not the component focused testing contained in the PRC-005 maintenance standard.

Since the functional test operates the RAS under controlled conditions with known System states and expected results, testing and analysis can be performed with minimum impact to the BES and should align with expected results. The RAS-entity is in the best position to determine the testing procedure and schedule due to their overall knowledge of the RAS design, installation, and functionality. Periodic testing provides the RAS-entity assurance that latent failures may be identified and also promotes identification of changes in the System that may have introduced latent failures.

The six and twelve full calendar year functional testing intervals are greater than the annual or bi-annual periodic testing performed in some NERC Regions. However, these intervals are a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS. Longer test intervals for limited impact RAS are acceptable because incorrect operations or failures to operate present a low reliability risk to the Bulk Power System.

Functional testing is not synonymous with end-to-end testing. End-to-end testing is an acceptable method but may not be feasible for many RAS. When end-to-end testing is not possible, a RAS-entity may use a segmented functional testing approach. The segments can be tested individually negating the need for complex maintenance schedules. In addition, actual RAS operation(s) can be used to fulfill the functional testing requirement. If a RAS does not operate in its entirety during a System event or System conditions do not allow an end-to-end scheme test, then the segmented approach should be used to fulfill this Requirement. Functional testing includes the testing of all RAS inputs used for detection, arming, operating, and data collection. Functional testing also includes the processing logic and infrastructure of a RAS as well as the action initiation by RAS outputs to address the System condition(s) for which the RAS is designed. All segments and components of a RAS must be tested or have proven operations within the applicable maximum test interval to demonstrate compliance with the Requirement.

As an example of segment testing, consider a RAS controller implemented using a PLC that receives System data, such as loading or line status, from distributed devices. These distributed devices could include meters, protective relays, or other PLCs. In this example RAS, a line protective relay is used to provide an analog metering quantity to the RAS control PLC. A functional test would verify that the System data is received from the protective relay by the PLC, processed by the PLC, and that PLC outputs are appropriate. There is no need to verify the protective relay's ability to measure the power system quantities, as this is a requirement for Protection Systems used as RAS in PRC-005, Table 1-1, Component Type – Protective Relay. Rather the functional test is focused on the use of the protective relay data at the PLC, including the communications data path from relay to PLC if this data is essential for proper RAS operation. Additionally, if the control signal back to the protective relay is also critical to the proper functioning of this example RAS, then that path is also verified up-to the protective relay. This example describes a test for one segment of a RAS which verifies RAS action, verifies PLC control logic, and verifies RAS communications.

IEEE C37.233, "IEEE Guide for Power System Protection Testing," 2009 section 8 (particularly 8.3-8.5), provides an overview of functional testing. The following opens section 8.3:

> Proper implementation requires a well-defined and coordinated test plan for performance evaluation of the overall system during agreed maintenance intervals. The maintenance test plan, also referred to as functional system testing, should include inputs, outputs, communication, logic, and throughput timing tests. The functional tests are generally not component-level testing, rather overall system testing. Some of the input tests may need to be done ahead of overall system testing to the extent that the tests affect the overall performance. The test coordinator or coordinators need to have full knowledge of the intent of the scheme, isolation points, simulation scenarios, and restoration to normal procedures.
>
> The concept is to validate the overall performance of the scheme, including the logic where applicable, to validate the overall throughput times against system modeling for different types of Contingencies, and to verify scheme performance as well as the inputs and outputs.

If a RAS passes a functional test, it is not necessary to provide that specific information to the RC because that is the expected result and requires no further action. If a segment of a RAS fails a functional test, the status of that degraded RAS is required to be reported (in Real-time) to the Transmission Operator via PRC-001, Requirement R6, then to the RC via TOP-001-3, Requirement R8. See Phase 2 of Project 2007-06 for the mapping document from PRC-001 to other standards regarding notification of RC by TOP if a deficiency is found during testing. Consequently, it is not necessary to include a similar requirement in this standard.

The initial test interval begins on the effective date of the standard pursuant to the implementation plan. Subsequently, the maximum allowable interval between functional tests is six full calendar years for RAS that are not designated as limited impact RAS and twelve full calendar years for RAS that are designated as limited impact RAS. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. A RAS-entity may choose to count a correct RAS operation as a qualifying functional test for those RAS segments which operate. If a System event causes a correct, but partial RAS operation, separate functional tests of the segments that did not operate are still required within the maximum test interval that started on the date of the previous successful test of those (non-operating) segments in order to be compliant with Requirement R8.

Requirement R9

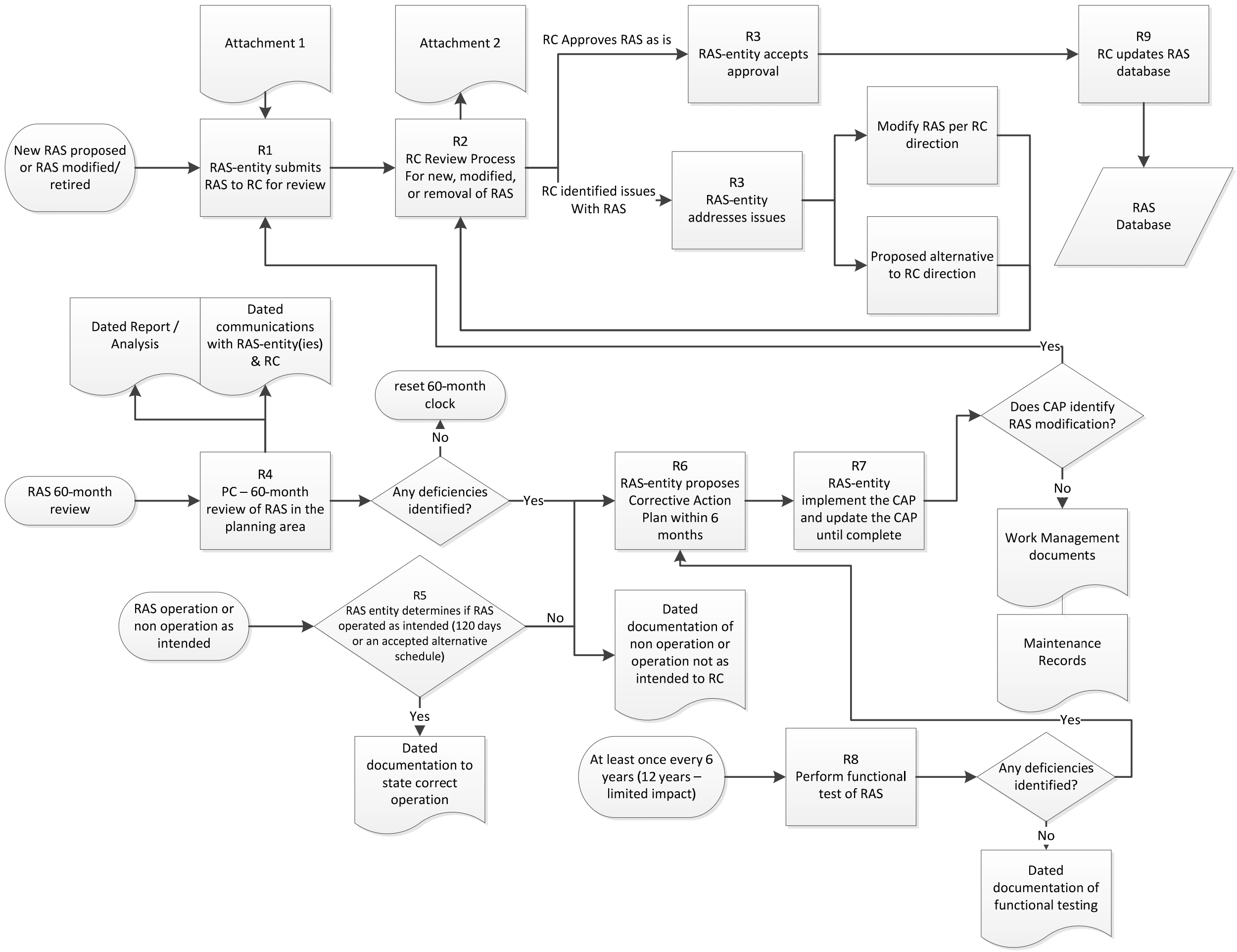
The RAS database required to be maintained by the RC in Requirement R9 ensures information regarding existing RAS is available to entities with a potential reliability need. Attachment 3 contains the minimum information that is required to be included about each RAS listed in the database. Additional information can be requested by the RC.

The information provided is sufficient for an entity with a reliability need to evaluate whether the RAS can impact its System. For example, a RAS performing generation rejection to mitigate an overload on a transmission line may cause a power flow change within an adjacent entity area. This entity should be able to evaluate the risk that a RAS poses to its System from the high-level information provided in the RAS database.

The RAS database does not need to list detailed settings or modeling information, but the description of the System performance issues, System conditions, and the intended corrective actions must be included. If additional details about the RAS operation are required, the entity may obtain the contact information of the RAS-entity from the RC.

Process Flow Diagram

The diagram below depicts the process flow of the PRC-012-2 requirements.



Technical Justifications for Attachment 1 Content
Supporting Documentation for RAS Review

To perform an adequate review of the expected reliability implications of a Remedial Action Scheme (RAS), it is necessary for the RAS-entity(ies) to provide a detailed list of information describing the RAS to the reviewing RC. If there are multiple RAS-entities for a single RAS, information will be needed from all RAS-entities. Ideally, in such cases, a single RAS-entity will take the lead to compile all the data identified into a single Attachment 1.

The necessary data ranges from a general overview of the RAS to summarized results of transmission planning studies, to information about hardware used to implement the RAS. Coordination between the RAS and other RAS and protection and control systems will be examined for possible adverse interactions. This review can include wide-ranging electrical design issues involving the specific hardware, logic, telecommunications, and other relevant equipment and controls that make up the RAS.

Attachment 1

The following checklist identifies important RAS information for each new or functionally modified[7] RAS that the RAS-entity shall document and provide to the RC for review pursuant to Requirement R1. When a RAS has been previously reviewed, only the proposed modifications to that RAS require review; however, it will be helpful to each reviewing RC if the RAS-entity provides a summary of the existing RAS functionality.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.

   Provide a description of the RAS to give an overall understanding of the functionality and a map showing the location of the RAS. Identify other protection and control systems requiring coordination with the RAS. See RAS Design below for additional information.

   Provide a single-line drawing(s) showing all sites involved. The drawing(s) should provide sufficient information to allow the RC review team to assess design reliability, and should include information such as the bus arrangement, circuit breakers, the associated switches, etc. For each site, indicate whether detection, logic, action, or a combination of these is present.

2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.

3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP. [Reference NERC Reliability Standard PRC-012-2, Requirements R5 and R7]

[7] Functionally Modified: Any modification to a RAS consisting of any of the following:

- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement of existing components
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

Provide a description of any functional modifications to a RAS that are part of a CAP that are proposed to address performance deficiency(ies) identified in the periodic evaluation pursuant to Requirement R4, the analysis of an actual RAS operation pursuant to Requirement R5, or functional test failure pursuant to Requirement R8. A copy of the most recent CAP must be submitted in addition to the other data specified in Attachment 1.

4. Initial data to populate the RAS database.

   a. RAS name

   b. Each RAS-entity and contact information

   c. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent 60 full calendar month (Requirement R4) evaluation date; and, date of retirement, if applicable

   d. System performance issue or reason for installing the RAS (*e.g.*, thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery)

   e. Description of the Contingencies or System conditions for which the RAS was designed (initiating conditions)

   f. Corrective action taken by the RAS

   g. Identification of limited impact[8] RAS

   h. Any additional explanation relevant to high level understanding of the RAS

   Note: This is the same information as is identified in Attachment 3. Supplying the data at this point in the review process ensures a more complete review and minimizes any administrative burden on the reviewing RC(s).

II. Functional Description and Transmission Planning Information

1. Contingencies and System conditions that the RAS is intended to remedy. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.1]

   a. The System conditions that would result if no RAS action occurred should be identified.

   b. Include a description of the System conditions that should arm the RAS so as to be ready to take action upon subsequent occurrence of the critical System Contingencies or other operating conditions when RAS action is intended to occur. If no arming conditions are required, this should also be stated.

[8] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. See Attachment 2 for a description of the limited impact determination by the Reliability Coordinator. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.

c. Event-based RAS are triggered by specific Contingencies that initiate mitigating action. Condition-based RAS may also be initiated by specific Contingencies, but specific Contingencies are not always required. These triggering Contingencies and/or conditions should be identified.

2. The actions to be taken by the RAS in response to disturbance conditions. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.2]

   Mitigating actions are designed to result in acceptable System performance. These actions should be identified, including any time constraints and/or "backup" mitigating measures that may be required in case of a single RAS component failure.

3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and when those technical studies were performed. [Reference NEC Reliability Standard PRC-014, R3.2]

   Review the scheme purpose and impact to ensure it is (still) necessary, serves the intended purposes, and meets current performance requirements. While copies of the full, detailed studies may not be necessary, any abbreviated descriptions of the studies must be detailed enough to allow the reviewing RC(s) to be convinced of the need for the scheme and the results of RAS-related operations.

4. Information regarding any future System plans that will impact the RAS. [Reference NERC Reliability Standard PRC-014, R3.2]

   The RC's other responsibilities under the NERC Reliability Standards focus on the Operating Horizon, rather than the Planning Horizon. As such, the RC is less likely to be aware of any longer range plans that may have an impact on the proposed RAS. Such knowledge of future Plans is helpful to provide perspective on the capabilities of the RAS.

5. RAS-entity proposed designation as "limited impact" or not.

   A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact for the purposes of Requirement 4, Parts 4.1.3 and 4.1.4.

6. Documentation showing that the possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following: [Reference NERC Reliability Standard PRC-012, R1.4]

   a. The BES shall remain stable.

   b. Cascading shall not occur.

c. Applicable Facility Ratings shall not be exceeded.

d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

7. An evaluation indicating that the RAS settings and operation avoids adverse interactions with other RAS, and protection and control systems.
[Reference NERC Reliability Standards PRC-012, R1.5 and PRC-014, R3.4]

   RAS are complex schemes that may take action such as tripping load or generation or re-configuring the System. Many RAS depend on sensing specific System configurations to determine whether they need to arm or take actions. An examples of an adverse interaction: A RAS that reconfigures the System also changes the available fault duty, which can affect distance relay overcurrent ("fault detector") supervision and ground overcurrent protection coordination.

8. Identification of other affected RCs.

   This information is needed to aid in information exchange among all affected entities and coordination of the RAS with other RAS and protection and control systems.

III. Implementation

1. Documentation describing the applicable equipment used for detection, dc supply, communications, logic processing, control actions, and monitoring.

Detection

Detection and initiating devices, whether for arming or triggering action, should be designed to be secure. Several types of devices have been commonly used as disturbance, condition, or status detectors:

- Line open status (event detectors),
- Protective relay inputs and outputs (event and parameter detectors),
- Transducer and IED (analog) inputs (parameter and response detectors),
- Rate of change (parameter and response detectors).

DC Supply

Batteries and charges, or other forms of dc supply for RAS, are commonly also used for Protection Systems. This is acceptable, and maintenance of such supplies is covered by PRC-005. However, redundant RAS systems, when used, should be supplied from separately protected (fused or breakered) circuits.

Communications: Telecommunications Channels and Transfer Trip Equipment

Telecommunications channels used for sending and receiving RAS information between sites and/or transfer trip devices should meet at least the same criteria as other relaying protection communication channels. Discuss performance of any non-deterministic communication systems used (such as Ethernet).

The scheme logic should be designed so that loss of the channel, noise, or other channel or equipment failure will not result in a false operation of the scheme.

It is highly desirable that the channel equipment and communications media (power line carrier, microwave, optical fiber, etc.) be owned and maintained by the RAS-entity, or perhaps leased from another entity familiar with the necessary reliability requirements. All channel equipment should be monitored and alarmed to the dispatch center so that timely diagnostic and repair action shall take place upon failure. Publicly switched telephone networks are generally an undesirable option.

Communication channels should be well labeled or identified so that the personnel working on the channel can readily identify the proper circuit. Channels between entities should be identified with a common name at all terminals.

Transfer trip equipment, when separate from other RAS equipment, should be monitored and labeled similarly to the channel equipment.

Logic Processing

All RAS require some form of logic processing to determine the action to take when the scheme is triggered. Required actions are always scheme dependent. Different actions may be required at different arming levels or for different Contingencies. Scheme logic may be achievable by something as simple as wiring a few auxiliary relay contacts or by much more complex logic processing.

Platforms that have been used reliably and successfully include PLCs in various forms, personal computers (PCs), microprocessor protective relays, remote terminal units (RTUs), and logic processors. Single-function relays have been used historically to implement RAS, but this approach is now less common except for very simple new RAS or minor additions to existing RAS.

Control Actions

RAS action devices may include a variety of equipment such as transfer trip, protective relays, and other control devices. These devices receive commands from the logic processing function (perhaps through telecommunication facilities) and initiate RAS actions at the sites where action is required.

Monitoring by SCADA/EMS should include at least

- Whether the scheme is in-service or out of service.
  - For RAS that are armed manually, the arming status may be the same as whether the RAS is in-service or out of service.
  - For RAS that are armed automatically, these two states are independent because a RAS that has been placed in-service may be armed or unarmed based on whether the automatic arming criteria have been met.
- The current operational state of the scheme (available or not).

- In cases where the RAS requires single component failure performance; e.g., redundancy, the minimal status indications should be provided separately for each system.
  - The minimum status is generally sufficient for operational purposes; however, where possible it is often useful to provide additional information regarding partial failures or the status of critical components to allow the RAS-entity to more efficiently troubleshoot a reported failure. Whether this capability exists will depend in part on the design and vintage of equipment used in the RAS. While all schemes should provide the minimum level of monitoring, new schemes should be designed with the objective of providing monitoring at least similar to what is provided for microprocessor-based Protection Systems.

2. Information on detection logic and settings/parameters that control the operation of the RAS. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.3]

   Several methods to determine line or other equipment status are in common use, often in combination:

   a. Auxiliary switch contacts from circuit breakers and disconnect switches (52a/b, 89a/b)—the most common status monitor; “a” contacts exactly emulate actual breaker status, while “b” contacts are opposite to the status of the breaker;

   b. Undercurrent detection—a low level indicates an open condition, including at the far end of a line; pickup is typically slightly above the total line-charging current;

   c. Breaker trip coil current monitoring—typically used when high-speed RAS response is required, but usually in combination with auxiliary switch contacts and/or other detection because the trip coil current ceases when the breaker opens; and

   d. Other detectors such as angle, voltage, power, frequency, rate of change of the aforementioned, out of step, etc. are dependent on specific scheme requirements, but some forms may substitute for or enhance other monitoring described in items ‘a’, ‘b’, and ‘c’ above.

   Both RAS arming and action triggers often require monitoring of analog quantities such as power, current, and voltage at one or more locations and are set to detect a specific level of the pertinent quantity. These monitors may be relays, meters, transducers, or other devices

3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in-service or is being maintained.

   In this context, a multifunction device (e.g., microprocessor-based relay) is a single component that is used to perform the function of a RAS in addition to protective relaying and/or SCADA simultaneously. It is important that other applications in the multifunction device do not compromise the functionality of the RAS when the device is in service or when it is being maintained. The following list outlines considerations when the RAS function is applied in the same microprocessor-based relay as equipment protection functions:

a. Describe how the multifunction device is applied in the RAS.

b. Show the general arrangement and describe how the multi-function device is labeled in the design and application, so as to identify the RAS and other device functions.

c. Describe the procedures used to isolate the RAS function from other functions in the device.

d. Describe the procedures used when each multifunction device is removed from service and whether coordination with other protection schemes is required.

e. Describe how each multifunction device is tested, both for commissioning and during periodic maintenance testing, with regard to each function of the device.

f. Describe how overall periodic RAS functional and throughput tests are performed if multifunction devices are used for both local protection and RAS.

g. Describe how upgrades to the multifunction device, such as firmware upgrades, are accomplished. How is the RAS function taken into consideration?

Other devices that are usually not considered multifunction devices such as auxiliary relays, control switches, and instrument transformers may serve multiple purposes such as protection and RAS. Similar concerns apply for these applications as noted above.

4. Documentation describing the System performance resulting from a single component failure in the RAS, except for limited impact RAS, when the RAS is intended to operate. A single component failure in a RAS not determined to be limited impact must 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 is designed. The documentation should describe or illustrate how the design achieves this objective. [Reference NERC Reliability Standard PRC-012, R1.3]

   RAS automatic arming, if applicable, is vital to RAS and System performance and is therefore included in this requirement. Acceptable methods to achieve this objective include, but are not limited to the following:

   a. Providing redundancy of RAS components. Typical examples are listed below:

      i. Protective or auxiliary relays used by the RAS.

      ii. Communications systems necessary for correct operation of the RAS.

      iii. Sensing devices used to measure electrical or other quantities used by the RAS.

      iv. Station dc supply associated with RAS functions.

      v. Control circuitry associated with RAS functions through the trip coil(s) of the circuit breakers or other interrupting devices.

vi. Logic processing devices that accept System inputs from RAS components or other sources, make decisions based on those inputs, or initiate output signals to take remedial actions.

b. Arming more load or generation than necessary such that failure of the RAS to drop a portion of load or generation due to that single component failure will still result in satisfactory System performance, as long as tripping the total armed amount of load or generation does not cause other adverse impacts to reliability.

c. Using alternative automatic actions to back up failures of single RAS components.

d. 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.

5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies important RAS information for each existing RAS to be retired that the RAS-entity shall document and provide to the Reliability Coordinator for review pursuant to Requirement R1.

1. Information necessary to ensure that the Reliability Coordinator is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of technical studies, if applicable, upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

While the documentation necessary to evaluate RAS removals is not as extensive as for new or functionally modified RAS, it is still vital that, when the RAS is no longer available, System performance will still meet the appropriate (usually TPL) requirements for the Contingencies or System conditions that the RAS had been installed to remediate.

Technical Justification for Attachment 2 Content

Reliability Coordinator RAS Review Checklist

Attachment 2 is a checklist provided to facilitate consistent reviews continent-wide for new or functionally modified RAS prior to the RAS installation. The checklist is meant to assist the RC in identifying reliability-related considerations relevant to various aspects of RAS design and implementation.

Technical Justifications for Attachment 3 Content

Database Information

Attachment 3 contains the minimum information that the RC must consolidate into its database for each RAS in its area.

1. RAS name.
    - The name used to identify the RAS.
2. Each RAS-entity and contact information.
    - A reliable phone number or email address should be included to contact each RAS-entity if more information is needed.
3. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent 60 full calendar month (Requirement R4) evaluation date; and, date of retirement, if applicable.
    - Specify each applicable date.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery).
    - A short description of the reason for installing the RAS is sufficient, as long as the main System issues addressed by the RAS can be identified by someone with a reliability need.
5. Description of the Contingencies or System conditions for which the RAS was designed (initiating conditions).
    - A high level summary of the conditions/Contingencies is expected. Not all combinations of conditions are required to be listed.
6. Corrective action taken by the RAS.
    - A short description of the actions should be given. For schemes shedding load or generation, the maximum amount of megawatts should be included.

7. Identification of limited impact[9] RAS.
    - Specify whether or not the RAS is designated as limited impact.
8. Any additional explanation relevant to high-level understanding of the RAS.
    - If deemed necessary, any additional information can be included in this section, but is not mandatory.

[9] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

Draft ~~1~~2 of PRC-012-2 corrects the applicability of the fill-in-the-blank standards (PRC-012-1, PRC-013-1, and PRC-014-1) by assigning the requirement responsibilities to the specific users, owners, and operators of the Bulk-Power System, and incorporates the reliability objectives of all the RAS/SPS-related standards. ~~Draft 1~~This draft contains nine requirements and measures, the associated rationale boxes and corresponding technical guidelines. There are also three attachments within the draft standard that are incorporated via references in the requirements. ~~Draft 1of~~This draft of PRC-012-2 is posted for a 45-day ~~initial~~ formal comment period with a parallel ~~initial~~ ballot in the last ten days of the comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	February 12, 2014
SAR posted for comment	February 18, 2014
Standards Committee approved the SAR	June 10, 2014
Draft 1 of PRC-012-2 posted for informal comment	April 30 – May 20, 2015
45-day formal comment period with initial ballot	August 20 – October 5, 2015
45-day formal comment period with additional ballot	November 25, 2015 – January 8, 2016

Anticipated Actions	Date
10-day final ballot	~~December 2015~~March 2016
NERC Board (Board) adoption	~~February~~May 2016

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Remedial Action Schemes
2. **Number:** PRC-012-2
3. **Purpose:** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - ~~**4.1.2.** Transmission Planner~~
     - **4.1.2.** Planning Coordinator
     - **4.1.3.** RAS-~~owner~~entity – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS
     - ~~**4.1.4.** RAS-entity – the RAS-owner designated to represent all RAS-owner(s) for coordinating the review and approval of a RAS~~
   - **4.2. Facilities:**
     - **4.2.1.** Remedial Action Schemes (RAS)
5. **Effective Date:** See the Implementation Plan for PRC-012-2.

B. Requirements and Measures

Rationale for Requirement R1: Each Remedial Action Scheme (RAS) is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES). Therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification or retirement ~~(~~; i.e., removal from service~~)~~ must be completed prior to implementation or retirement. ~~A functional modification is~~

Functional modifications consist of any ~~modification~~of the following:

- Changes to ~~a RAS~~System conditions or Contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond ~~the~~in-kind replacement of existing components ~~that preserves the original functionality.~~
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

To facilitate a review that promotes reliability, the RAS-entity must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity provide them to the reviewing Reliability Coordinator (RC). The RC (reviewing RC) that coordinates the area where the RAS is located is responsible for the review. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate and submit a single, coordinated Attachment 1 to the reviewing RC. In cases where a RAS crosses one or more RC Area boundaries, each affected RC is responsible for conducting either individual reviews or participating in a coordinated review.

R1. Prior to placing a new or functionally modified RAS in~~-~~service or retiring an existing RAS, each RAS-entity shall ~~submit~~provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) ~~that coordinates the area(s)~~ where the RAS is located. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, a copy of the Attachment 1 documentation and the dated communications with the reviewing Reliability Coordinator(s) in accordance with Requirement R1.

Rationale for Requirement R2: The RC is the functional entity best suited to perform the RAS review because it has the widest-area operational and reliability perspective of all functional entities and an awareness of reliability issues in any neighboring RC Area. This Wide Area purview ~~provides continuity in the review process and~~ facilitates the evaluation of interactions among separate RAS as well as interactions among RAS and other protection and control systems. ~~Including~~Review by the RC also minimizes the possibility of a conflict of interest that could exist because of business relationships among the RAS-entity, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC is not expected to possess more information or ability than anticipated by their functional registration as designated by NERC. The RC may request assistance ~~in~~to perform RAS reviews from other parties such as the PC or regional technical groups; however, the RC will retain the responsibility for compliance with this requirement.

Attachment 2 of this standard is a checklist the RC can use to identify design and implementation aspects of RAS and facilitate consistent reviews for each ~~RAS~~ submitted RAS. The time frame of four- full- calendar months is consistent with current utility and regional practice; however, flexibility is provided by allowing the ~~parties~~RC(s) and RAS-entity(ies) to negotiate a mutually agreed upon schedule for the review.

Note: An RC may need to include this task in its reliability plan(s) for the NERC Regions(s) in which it is located.

R2. Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1~~,~~ shall, within four- full- calendar months of receipt~~,~~ or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to ~~the~~each RAS-entity. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated reports, checklists, or other documentation detailing the RAS review, and the dated communications with the RAS-entity in accordance with Requirement R2.

Rationale for Requirement R3: The RC review is intended to identify reliability issues that must be resolved before the RAS can be put in--service. Examples of reliability issues include a lack of dependability, security, or coordination.

A specific time period for the RAS-entity to respond to the ~~RC review~~reviewing RC following identification of any reliability issue(s) is not necessary because ~~it is in~~ the RAS-~~entity's interest~~entity wants to ~~obtain an expeditious response from~~expedite the ~~entity and thus ensure a~~ timely approval and subsequent implementation~~.~~ of the RAS.

R3. ~~Following the review performed pursuant to Requirement R2, the RAS-entity shall address each identified issue and obtain approval from each reviewing Reliability Coordinator prior~~Prior to placing a new or functionally modified RAS in--service or retiring an existing RAS~~.~~, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Acceptable evidence may include, but is not limited to, dated documentation and communications with the reviewing Reliability Coordinator that no reliability issues were identified during the review or that all identified reliability issues were resolved in accordance with Requirement R3.

Rationale for Requirement R4: Requirement R4 mandates that an evaluation of each RAS be performed at least once every sixty~~-~~ full~~-~~ calendar months. The purpose of ~~a~~the periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that~~ requirements for BES performance following an inadvertent ~~, if a RAS ~~operation or a ~~single component failure ~~in the RAS continues~~or single component malfunction were to occur, the requirements for BES performance would continue to be satisfied. ~~A~~The periodic evaluation is needed because changes in ~~system~~System topology or operating conditions ~~that have occurred since the previous RAS evaluation—or initial review—was completed ~~may change the effectiveness of a RAS or the way it impacts the BES.

~~Sixty full calendar months,~~ Requirement R4 also clarifies that the RAS single component failure and single component malfunction tests do not apply to RAS which ~~begins on~~are determined to be limited impact. A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented after the effective date of ~~the~~this standard ~~pursuant to~~will be designated as limited impact or not by the ~~implementation plan,~~reviewing RC(s) during its review. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact for the purposes of Requirement 4, Parts 4.1.3 and 4.1.4. Requiring a limited impact RAS to meet the single component failure and single component malfunction tests would add complexity to the design with minimal benefit to the reliability of the BES. See Attachment 2 for a description of the limited impact determination by the Reliability Coordinator.

For existing RAS, the initial performance of Requirement R4 must be completed within sixty full calendar months of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within sixty full calendar months of the RAS approval date by the reviewing RC(s). Sixty full calendar months was selected as the maximum time frame between evaluations based on the time frames for similar requirements in Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation can be performed sooner if it is determined that material changes to ~~system~~System topology or ~~system~~System operating conditions~~ have occurred that~~ could potentially impact the effectiveness or coordination of the RAS. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluation ~~are planning analyses that~~may involve modeling of the interconnected transmission system to assess BES performance~~; consequently, the TP~~. The Planning Coordinator (PC) is the functional entity best suited to perform ~~the analyses.~~this evaluation because they have a wide area planning perspective. To promote reliability, the ~~TP~~PC is required to provide the ~~RAS-owner(s) and each~~

~~reviewing RC with the~~ results of the evaluation~~.~~ to each impacted Transmission Planner and Planning Coordinator, in addition to each reviewing RC and RAS-entity.

The previous version of this standard (PRC-012-~~0~~1 Requirement 1, R1.4) states "… 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~~Contingency for which it was designed, and not exceed TPL-003-0." Requirement R4 clarifies that the inadvertent operation to be considered would only be that caused by the malfunction of a single RAS component. This allows security features to be designed into the RAS such that inadvertent operation due to a single component malfunction is prevented. Otherwise ~~and~~, consistent with PRC-012-~~0~~1 Requirement 1, R1.4, the RAS should be designed so that its whole or partial inadvertent operation due to a single component malfunction satisfies the ~~system~~System 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 some other Contingency or System condition not defined in TPL-001-4 (therefore without performance requirements), its inadvertent operation still must meet some minimum System performance requirements. However, instead of referring to the TPL-001-4, Requirement R4 lists the System performance requirements that the inadvertent operation must satisfy. The performance requirements listed (Parts 4.1.3.1 – 4.1.3.5) are the ones that are common to all planning events P0-P7 listed in TPL-001-4.

R4. Each ~~Transmission Planner shall perform an evaluation of each RAS within its planning area~~ Planning Coordinator, at least once every 60~~-~~ full~~-~~ calendar~~-~~ months ~~and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether:~~, shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Perform an evaluation of each RAS within its planning area to determine whether:

~~4.1.~~4.1.1. The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed.

~~4.2.~~4.1.2. The RAS avoids adverse interactions with other RAS, and protection and control systems.

~~4.3.~~4.1.3. ~~The~~ Except for "limited impact"[1] RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following:

[1] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. See Attachment 2 for a description of the limited impact determination by the Reliability

~~4.3.1.~~4.1.3.1. The BES shall remain stable.

~~4.3.2.~~4.1.3.2. Cascading shall not occur.

~~4.3.3.~~4.1.3.3. Applicable Facility Ratings shall not be exceeded.

~~4.3.4.~~4.1.3.4. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

~~4.3.5.~~4.1.3.5. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

~~4.4.~~4.1.4. ~~A~~Except for limited impact RAS, 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 is designed.

4.2. Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.

M4. Acceptable evidence may include, but is not limited to, dated reports or other documentation of the analyses comprising the evaluation(s) of each RAS and dated communications with the RAS-~~owner(s)~~entity(ies), Transmission Planner(s), Planning Coordinator(s), and the reviewing Reliability Coordinator(s) in accordance with Requirement R4.

Rationale for Requirement R5: The correct operation of a RAS is important for maintaining the reliability and integrity of the BES. Any incorrect operation of a RAS indicates that the RAS effectiveness and/or coordination has been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design. A RAS operational performance analysis is intended to: 1) verify RAS operation ~~is~~was consistent with the implemented design; or 2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected. The 120~~-~~ full calendar~~-~~ day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation. ~~-~~To promote

Coordinator. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact for the purposes of Requirement 4, Parts 4.1.3 and 4.1.4.

reliability, each RAS-~~owner~~entity is required to provide the results of RAS operational performance analyses ~~to each~~that identified any deficiencies to its reviewing RC~~.~~(s).

RAS-~~owners~~entities may need to collaborate with their associated ~~TP~~Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation ~~triggers and responds (Parts~~was triggered correctly (Part 5.1~~,~~.1), responded as designed (Part 5.1.2~~)~~), and that the resulting BES response (Parts 5.1.3~~,~~ and 5.1.4) ~~is~~was consistent with the intended functionality and design of the RAS. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate on the operational performance analysis.

R5. Each RAS-~~owner shall~~entity, within 120~~-~~ full calendar days of a RAS operation or a failure of ~~a~~its RAS to operate when expected, ~~analyze the RAS performance and provide the results of the analysis, including any identified deficiencies, to~~or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s~~). The RAS operational performance analysis shall determine whether:~~), shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Participate in analyzing the RAS operational performance to determine whether:

~~5.1.~~5.1.1. The System events and/or conditions appropriately triggered the RAS.

~~5.2.~~5.1.2. The RAS responded as designed.

~~5.3.~~5.1.3. The RAS was effective in mitigating BES performance issues it was designed to address.

~~5.4.~~5.1.4. The RAS operation resulted in any unintended or adverse BES response.

5.2. Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).

M5. Acceptable evidence may include, but is not limited to, dated documentation detailing the results of the RAS operational performance analysis and dated communications with the reviewing Reliability Coordinator(s) in accordance with Requirement R5.

Rationale for Requirement R6: Deficiencies~~,~~ identified ~~either~~ in the periodic RAS evaluation conducted by the ~~TP in~~PC pursuant to Requirement R4 ~~or~~, in the operational performance analysis conducted by the RAS-~~owner~~entity pursuant to Requirement R5, ~~are likely to~~or in the functional test performed by the RAS-entity pursuant to Requirement R8, potentially pose a reliability risk to the BES. To mitigate these potential reliability risks, Requirement R6 mandates that ~~the~~each RAS-~~owner~~entity develop a Corrective Action Plan (CAP) ~~that establishes~~to address the identified deficiency. The CAP contains the mitigation actions and associated timetable ~~to address the deficiency.~~ necessary to remedy the specific deficiency. The RAS-entity may request assistance with

CAP development from other parties such as its Transmission Planner or Planning Coordinator; however, the RAS-entity has the responsibility for compliance with this requirement.

If the CAP requires that a functional change be made to a RAS, the RAS-~~owner~~entity will need to submit information identified in Attachment 1 to the reviewing RC(s) prior to placing RAS modifications in-~~-~~service per Requirement R1.

Depending on the complexity of the ~~issues,~~identified deficiency(ies), development of a CAP ~~might~~may require ~~study,~~studies, and other engineering~~,~~ or consulting work. A maximum time frame of six~~-~~ full~~-~~ calendar months is specified ~~to allow enough time~~ for RAS-~~owner~~entity collaboration on the CAP development~~, while ensuring that deficiencies are addressed in a reasonable time.~~ .

R6. ~~Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner~~Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s~~).~~) within six full calendar months of: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

- Being notified of a deficiency in its RAS pursuant to Requirement R4, or
- Notifying the Reliability Coordinator pursuant to Requirements R5, or
- Identifying a deficiency in its RAS pursuant to Requirement R8.

M6. Acceptable evidence may include, but is not limited to, a dated CAP and dated communications ~~with~~among each reviewing Reliability Coordinator and each RAS-entity in accordance with Requirement R6.

Rationale for Requirement R7: Requirement R7 mandates ~~the~~each RAS-~~owner(s)~~entity implement a CAP (developed in Requirement R6) that mitigates the deficiencies identified in Requirements R4~~ and~~, R5, or R8. By definition, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem." The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. Each reviewing Reliability Coordinator must be notified if CAP actions or timetables change~~.~~, and when the CAP is completed.

R7. ~~For~~Each RAS-entity shall, for each ~~CAP submitted~~of its CAPs developed pursuant to Requirement R6~~, each RAS-owner shall~~: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

7.1. Implement the CAP.

7.2. Update the CAP if actions or timetables change.

7.3. Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

M7. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, and communication with the ~~appropriate~~reviewing Reliability Coordinator(s) that documents the implementation ~~or~~, updating, or completion of a CAP in accordance with Requirement R7.

Rationale for Requirement R8: Due to the wide variety of RAS designs and implementations, and the potential for impacting BES reliability, it is important that periodic functional testing of a RAS be performed. A functional test provides an overall confirmation of the RAS to operate as designed and verifies the proper operation of the non-Protection System (control) components of a RAS that are not addressed in PRC-005. Protection System components that are part of a RAS are maintained in accordance with PRC-005. ~~The drafting team selected a six-calendar-year testing interval to be consistent with some of the maintenance intervals of various Protection System and Automatic Reclosing components established in PRC-005. This interval provides an entity the opportunity to design its RAS functional testing program such that it coincides with the testing of any associated PRC-005 components.~~

The six~~-~~ or twelve full calendar~~-~~ year test interval, which begins on the effective date of the standard pursuant to the PRC-012-2 implementation plan, is a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS. Extending to longer intervals increases the reliability risk to the BES posed by ~~a potentially~~an undiscovered latent failure that could cause an incorrect operation or failure of the RAS. The RAS-~~owner~~entity is in the best position to determine the testing procedure and schedule due to its overall knowledge of the RAS design, installation, and functionality. Functional testing may be accomplished with end-to-end testing or a segmented approach. ~~Each~~For segmented testing, each segment of a RAS ~~should~~must be tested ~~but overlapping~~. Overlapping segments can be tested individually negating the need for complex maintenance schedules and outages.

The maximum allowable interval between functional tests is six full calendar years for RAS that are not designated as limited impact RAS and twelve full calendar years for RAS that are designated as limited impact RAS. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. A correct operation of a RAS qualifies as a functional test ~~as long as all~~for those RAS segments which operate~~.~~ (documentation for compliance with Requirement R5 Part 5.1). If an event causes a partial operation of a RAS, the segments without an operation will require a separate functional test within the ~~six year interval to be compliant with Requirement R8~~maximum interval with the starting date determined by the previous successful test of the segments that did not operate.

R8. ~~At least once every six calendar years, each~~Each RAS-~~owner~~entity shall ~~perform~~participate in performing a functional test of each of its RAS to verify the overall RAS performance and the proper operation of non-Protection System components~~.~~: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

- At least once every six full calendar years for all RAS not designated as limited impact, or
- At least once every twelve full calendar years for all RAS designated as limited impact

M8. Acceptable evidence may include, but is not limited to, dated documentation ~~of~~detailing the RAS operational performance analysis for a correct RAS segment or an end-to-end operation (Measure M5 documentation), or dated documentation demonstrating that a functional ~~testing~~test of each RAS segment or an end-to-end test was performed in accordance with Requirement R8.

Rationale for Requirement R9: The RAS database is a comprehensive record of all RAS existing in a Reliability Coordinator Area. The database enables the RC to provide other entities high-level information on existing RAS that ~~can~~could potentially impact the ~~entities'~~ operational and/or planning activities of that entity. Attachment 3 lists the minimum information required for the RAS database, which includes a summary of the RAS initiating conditions, corrective actions, and System issues being mitigated. This information allows an entity to evaluate the reliability need for requesting more detailed information from the RAS-~~entity~~entities identified in the database contact information. The RC is the appropriate entity to maintain the database because the RC receives the required database information when a new or modified RAS is submitted for review. The twelve full calendar month time frame is aligned with industry practice and allows sufficient time for the RC to collect the appropriate information from RAS-entities and update the RAS database.

R9. Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once ~~each~~every twelve full calendar ~~year~~months. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M9. Acceptable evidence may include, but is not limited to, dated spreadsheets, database reports, or other documentation demonstrating a RAS database was ~~maintained~~updated in accordance with Requirement R9.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The RAS-entity (Transmission Owner, Generator Owner, and Distribution Provider) shall each keep data or evidence to show compliance with Requirements R1 ~~through~~, R3, R5, R6, R7, and R8, and Measures M1, M3, M5, M6, M7, and M8 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Reliability Coordinator shall each keep data or evidence to show compliance with Requirements R2 and R9, and Measures ~~M1 through~~M2 and M9 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Planning Coordinator shall each keep data or evidence to show compliance with Requirement R4 and Measure M4 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a RAS-entity (Transmission Owner, Generator Owner or Distribution Provider), Reliability Coordinator, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The RAS-entity failed to ~~submit~~provide the information identified in Attachment 1 to ~~one or more of the~~each Reliability Coordinator~~(s)~~ prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R1.
R2.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30~~-~~ full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30~~-~~ full calendar days but less than or equal to 60~~-~~ full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 60~~-~~ full calendar days but less than or equal to 90~~-~~ full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90~~-~~ full calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				accordance with Requirement R2.
R3.	N/A	N/A	N/A	The RAS-entity failed to resolve identified reliability issue(s) to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in -service or retiring an existing RAS in accordance with Requirement R3.
R4.	The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, but in greater than 60~~-~~ full~~-~~ calendar months but less than or equal to 61~~-~~ full~~-~~ calendar months.	The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, but in greater than 61~~-~~ full~~-~~ calendar months but less than or equal to 62~~-~~ full-calendar months.	The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, but in greater than 62~~-~~ full~~-~~ calendar months but less than or equal to 63~~-~~ full~~-~~ calendar months. OR The ~~Transmission Planner~~Planning Coordinator performed the evaluation in	The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, but in greater than 63~~-~~ full~~-~~ calendar months. OR ~~The Transmission Planner failed to perform the evaluation in accordance with Requirement R4.~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			accordance with Requirement R4, but failed to evaluate one of the Parts 4.1.1 through 4.1.4.	~~OR~~ ~~The Transmission Planner~~The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate two or more of the Parts 4.1.1 through 4.1.4. OR The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to provide the results to one or more of the ~~RAS-owner(s) and the reviewing Reliability Coordinator(s).~~receiving entities listed in Part 4.2. OR The Planning Coordinator failed to perform the evaluation in accordance with Requirement R4.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5.	The RAS-~~owner~~entity performed the analysis in ~~greater than 120-calendar days, but less than or equal to 130-calendar days in~~ accordance with Requirement R5, but was late by less than or equal to 10 full calendar days.	The RAS-~~owner~~entity performed the analysis in ~~greater~~accordance with Requirement R5, but was late by more than ~~130~~ 10 full calendar days~~,~~ but less than or equal to ~~140~~ 20 full calendar days ~~in accordance with Requirement R5~~.	The RAS-~~owner~~entity performed the analysis in ~~greater~~accordance with Requirement R5, but was late by more than ~~140~~ 20 full calendar days~~,~~ but less than or equal to ~~150~~ 30 full calendar days ~~in accordance with Requirement R5~~. OR The RAS-~~owner~~entity performed the analysis in accordance with Requirement R5, but failed to address one of the Parts 5.1.1 through 5.1.4.	The RAS-~~owner~~entity performed the analysis in ~~greater~~accordance with Requirement R5, but was late by more than ~~150~~ 30 full calendar days. OR ~~The RAS-owner failed to perform the analysis in accordance with Requirement R5.~~ ~~OR~~ ~~The RAS-owner~~The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address two or more of the Parts 5.1.1 through 5.1.4. OR The RAS-~~owner~~entity performed the analysis in accordance with Requirement R5, but failed to provide the results (Part 5.2) to one or more of the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				reviewing Reliability Coordinator(s). OR The RAS-entity failed to perform the analysis in accordance with Requirement R5.
R6.	The RAS-~~owner~~entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10~~-~~ full calendar days.	The RAS-~~owner~~entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10~~-~~ full calendar days but less than or equal to 20~~-~~ full calendar days.	The RAS-~~owner~~entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20~~-~~ full calendar days but less than or equal to 30~~-~~ full calendar days.	The RAS-~~owner~~entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30~~-~~ full calendar days. OR The RAS-~~owner~~entity developed a Corrective Action Plan ~~and~~but failed to submit it to one or more of its reviewing Reliability Coordinator(s) in accordance with Requirement R6. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The RAS-~~owner~~entity failed to develop a Corrective Action Plan in accordance with Requirement R6.
R7.	The RAS-~~owner~~entity implemented a CAP ~~(~~in accordance with Requirement R7, Part 7.1~~),~~, but failed to update the CAP (Part 7.2) if actions or timetables changed ~~and~~, or failed to notify ~~one or more~~(Part 7.3) each of the reviewing Reliability Coordinator(s) ~~(Part 7.3), in accordance with Requirement R7~~of the updated CAP or completion of the CAP.	N/A	N/A	The RAS-~~owner~~entity failed to implement a CAP ~~(Part 7.1)~~ in accordance with Requirement R7, Part 7.1.
R8.	The RAS-~~owner~~entity performed the functional test for a RAS as specified in Requirement R8, but was late by less than or equal to 30-~~ ~~full calendar days ~~late~~.	The RAS-~~owner~~entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 30-~~ ~~full calendar days but less than or equal to 60-~~ ~~full calendar days ~~late~~.	The RAS-~~owner~~entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 60-~~ ~~full calendar days but less than or equal to 90-~~ ~~full calendar days ~~late~~.	The RAS-~~owner~~entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 90-~~ ~~full calendar days ~~late~~. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The RAS-~~owner~~entity failed to perform the functional test for a RAS as specified in Requirement R8.
R9.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30~~-~~ full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30~~-~~ full calendar days but less than or equal to 60~~-~~ full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60~~-~~ full calendar days but less than or equal to 90~~-~~ full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90~~-~~ full calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

D. Regional Variances

None.

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
1		Adopted by NERC Board of Trustees	New

Attachment 1
Supporting Documentation for RAS Review

The following checklist identifies important Remedial Action Scheme (RAS) information for each new or functionally modified[2] RAS that the RAS-entity ~~shall~~must document and provide to the reviewing Reliability Coordinator(s) (RC~~) for review.~~). If an item on this list does not apply to a specific RAS, a response of ~~N/A or~~ "Not Applicable" for that item is appropriate. When ~~a~~ RAS ~~has been previously reviewed~~are submitted for functional modification review and approval, only the proposed modifications to that RAS require review; however, the RAS-entity must provide a summary of the ~~previously approved~~existing functionality. The RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS. Additional entities (without decision authority) may be part of the RAS review process at the request of the RC.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.
2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.
3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP. ~~[Reference NERC Reliability Standard PRC-012, Requirements R5 and R7]~~
4. Data to populate the RAS database:
   a. RAS name.
   b. Each RAS-entity and contact information.
   c. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
   d. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
   e. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
   f. Action(s) to be taken by the RAS.

[2] Functionally Modified: Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond ~~the~~in-kind replacement of existing components ~~that preserve the original functionality is a functional modification.~~
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

g. Identification of limited impact[3] RAS.

h. Any additional explanation relevant to high-level understanding of the RAS.

~~b.~~1. **Functional** ~~RAS-entity and contact information.~~

~~c.1.Expected or actual in-service date; most recent RC approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.~~

~~d.1. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).~~

II. Description ~~of the contingencies or~~ and Transmission Planning Information

~~e.~~1. Contingencies and System conditions ~~for which~~that the RAS ~~was designed (i.e., initiating conditions).~~is intended to remedy.

2. The action(s) to be taken by the RAS in response to disturbance conditions.

3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and the date those technical studies were performed.

4. Information regarding any future System plans that will impact the RAS.

5. RAS-entity proposed designation as limited impact or not.

6. Documentation describing the System performance resulting from the possible inadvertent operation of the RAS, except for limited impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be limited impact must satisfy all of the following:

    a. The BES shall remain stable.

    b. Cascading shall not occur.

    c. Applicable Facility Ratings shall not be exceeded.

    d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

    e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

[3] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. See Attachment 2 for a description of the limited impact determination by the Reliability Coordinator. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.

7. An evaluation indicating that the RAS settings and operation avoid adverse interactions with other RAS, and protection and control systems.

~~f. Action(s) to be taken by the RAS.~~

~~g.~~a.~~Any additional explanation relevant to high-level understanding of the RAS.~~

~~II.~~I. ~~Functional Description and Transmission Planning Information~~

~~1. Contingencies and System conditions that the RAS is intended to remedy. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.1]~~

~~2.~~1. ~~The action(s) to be taken by the RAS in response to disturbance conditions. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.2]~~

~~3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and the date those technical studies were performed. [Reference NERC Reliability Standard PRC-014, R3.2]~~

~~4.~~1. ~~Information regarding any future System plans that will impact the RAS. [Reference NERC Reliability Standard PRC-014, R3.2]~~

~~1. Documentation showing that the possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following: [Reference NERC Reliability Standard PRC-012, R1.4]~~

~~a. The BES shall remain stable.~~

~~b.~~a. ~~Cascading shall not occur.~~

~~c.~~a. ~~Applicable Facility Ratings shall not be exceeded.~~

~~d.~~a. ~~BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.~~

~~e.~~a. ~~Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.~~

~~5.~~1. ~~An evaluation indicating that the RAS settings and operation avoid adverse interactions with other RAS, and protection and control systems. [Reference NERC Reliability Standards PRC-012, R1.5 and PRC-014, R3.4]~~

~~6.~~8. Identification of other affected RCs.

III. Implementation

~~III.I. Implementation~~

1. Documentation describing the applicable equipment used for detection, ~~telecommunications~~dc supply, communications, transfer trip, control actions, logic processing, and monitoring.

~~2.~~ Information on detection logic and settings/parameters that control the operation of the RAS.~~Information on detection logic and settings/parameters that control the operation of the RAS. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.3]~~

2.

3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in~~-~~-service or is being maintained.

4. Documentation ~~showing that~~describing the System performance resulting from a single component failure in the RAS, except for limited impact RAS, when the RAS is intended to operate. A single component failure in a RAS not determined to be limited impact must 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 is designed. The documentation should describe or illustrate how the design achieves this objective.

~~4.1. , 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 is designed. The documentation should describe or illustrate how the design achieves this objective.~~
~~[Reference NERC Reliability Standard PRC-012, R1.3]~~

5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies RAS information that the RAS-entity shall document and provide to each reviewing RC.

1. Information necessary to ensure that the RC is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of applicable technical studies and technical justifications upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

Attachment 2
Reliability Coordinator RAS Review Checklist

The following checklist identifies reliability-related considerations for the Reliability Coordinator (RC) to review and verify for each new or functionally modified[4] Remedial Action Scheme (RAS). The RC review is not limited to the checklist items and the RC may request additional information on any ~~reliability issue related to the RAS.~~aspect of the RAS as well as any reliability issue related to the RAS. If a checklist item is not relevant to a particular RAS, it should be noted as "Not Applicable." If reliability considerations are identified during the review, the considerations and the proposed resolutions should be documented with the remaining applicable Attachment 2 items.

I. Design

1. The RAS actions satisfy performance objectives for the scope of events and conditions that the RAS is intended to mitigate.
2. The RAS arming conditions, if applicable, are appropriate to its System performance objectives.
3. The RAS avoids adverse interactions with other RAS, and protection and control systems.
4. The effects of RAS incorrect operation, including inadvertent operation and failure to operate ~~(if non-operation for RAS single component failure is acceptable),~~, have been identified.
5. ~~The~~Determination whether or not the RAS is "limited impact.[5]" A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

~~5.~~6. Except for limited impact RAS as determined by the RC, the possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following:

   a. The BES shall remain stable.

   b. Cascading shall not occur.

---

[4] Functionally Modified:
Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond ~~the~~in-kind replacement of existing components ~~that preserve the original functionality is a functional modification.~~
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

[5] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.

c. Applicable Facility Ratings shall not be exceeded.

d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

~~6.~~7. The effects of future BES modifications on the design and operation of the RAS have been identified, where applicable.

II. Implementation

1. The implementation of RAS logic appropriately correlates desired actions (outputs) with events and conditions (inputs).
2. The timing of RAS action(s) is appropriate to its BES performance objectives.

3. ~~A~~Except for limited impact RAS as determined by the RC, a single component failure in a RAS does not prevent the BES from meeting the same performance requirements as those required for the events and conditions for which the RAS is designed.
4. The RAS design facilitates periodic testing and maintenance.
5. The mechanism or procedure by which the RAS is armed is clearly described, and is appropriate for reliable arming and operation of the RAS for the conditions and events for which it is designed to operate.

III. RAS Retirement

RAS retirement reviews should assure that there is adequate justification for why a RAS is no longer needed.

Attachment 3
Database Information

1. RAS name.
2. Each RAS-entity and contact information.
3. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
5. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
6. Action(s) to be taken by the RAS.
7. Identification of limited impact[6] RAS.

~~2.a.RAS-entity and contact information.~~

~~3.a.Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.~~

~~4.a.System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).~~

~~5.a.Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).~~

~~6.a.Action(s) to be taken by the RAS.~~

~~7.~~8. Any additional explanation relevant to high-level understanding of the RAS.

[6] A RAS designated as “limited impact” cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.

Technical Justifications for Requirements

Applicability

4.1.~~4 RAS~~ 1 Reliability Coordinator

The Reliability Coordinator (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. The Wide-Area purview 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, Planning Coordinator, Transmission Planner, or other entities 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 purpose of the RAS-entity is to be the single information conduit with each reviewing Reliability Coordinator (RC) for all RAS-owners for each RAS. The RAS-entity needs to coordinate all review materials and any presentations. If all of the RAS equipment has a single owner, then the RAS-entity is the same as the RAS-owner and that owner speaks for itself.~~

4.1.2 Planning Coordinator

The Planning Coordinator (PC) is the best-suited functional entity to perform the RAS evaluation 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, similar to the planning analyses performed by PCs.

4.1.3 RAS-entity

The RAS-entity is any Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If all of the RAS (RAS components) have a single owner, then that RAS-entity has sole responsibility for all the activities assigned within the standard to the RAS-entity. If the RAS ~~equipment has~~(RAS components) have more than one owner, then each separate RAS ~~equipment owner is a RAS-owner. The RAS-entity will always be one of these RAS-owners. A RAS-entity will be selected by all RAS-owners and, traditionally, has usually been the owner of the RAS controller and a Transmission Owner. If a specific RAS-entity is not~~ component owner is a RAS-entity and is obligated to participate in various activities identified by the ~~RAS-owners, the RC will assign that function to the RAS-owner who provides the~~Requirements.

The standard does not stipulate particular compliance methods. RAS-entities have the option of collaborating to fulfill their responsibilities for each applicable requirement. Such collaboration and coordination may promote efficiency in achieving the reliability objectives of the requirements; however, the individual RAS-entity must be able to demonstrate its participation for compliance. As an example, the individual RAS-entities could collaborate to produce and submit a single, coordinated Attachment 1 to the reviewing RC pursuant to Requirement R1 to initiate the RAS review ~~material to them~~process.

~~The RAS-owner(s); i.e., Transmission Owner(s), Generator Owner(s), or Distribution Provider(s) who are not the RAS-entity still have responsibilities as assigned in other NERC Reliability Standards, such as equipment maintenance. In addition, when RAS modifications are needed, each RAS-owner of RAS equipment that must be modified must accept the specific responsibilities assigned to them as described in the necessary Corrective Action Plan (CAP), or otherwise as described in the revised Attachment 1.~~

Requirement R1

Each RAS is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES); therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification, or retirement (removal from service) must be completed prior to implementation.

~~Any modification~~Functional modifications consists of any of the following:

- Changes to System conditions or Contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond ~~the substitution~~in-kind replacement of existing components
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

An example indicating the limits of an in-kind replacement of a RAS component is the replacement of one relay (or other device) with a relay (or other device) that ~~merely preserve~~ uses similar functions. For instance, if a RAS included a CO-11 relay which was replaced by an IAC-53 relay, that would be an in-kind replacement. If the CO-11 relay were replaced by a microprocessor SEL-451 relay that used only the same functions as the original ~~functionality is~~ CO-11 relay, that would also be an in-kind replacement; however, if the SEL-451 relay was used to add new logic to what the CO-11 relay had provided, then the replacement relay would be a functional modification.

Changes to RAS pickup levels that require no other scheme changes are not considered a functional modification. ~~Any~~For example, System conditions require a RAS to be armed when the combined flow on two lines exceeds 500 MW. If a periodic evaluation pursuant to Requirement R4, or other assessment, indicates that the arming level should be reduced to 450 MW without requiring any other RAS changes that would not be a functional modification. Similarly, if a RAS is designed to shed load to reduce loading on a particular line below 1000 amps, then a change in ~~RAS logic such as new~~ the load shedding trigger from 1000 amps to 1100 amps would not be a functional modification.

Another example illustrates a case where a System change may result in a RAS functional change. Assume that a generation center is connected to a load center through two transmission lines. The lines are not rated to accommodate full plant output if one line is out of service, so a RAS monitors the status of both lines and trips or ramps down the generation to a safe level following loss of either line. Later, one of the lines is tapped to serve additional load. The System that the RAS impacts now includes three lines, loss of any of which is likely to still require generation reduction. The modified RAS will need to monitor all three lines (add two line terminal status inputs ~~or outputs, or any other modification that affects overall RAS functionality, or redundancy level as documented in the original submission~~to the RAS) and the logic to recognize the specific line outages would change, while the generation reduction (RAS output) requirement may or may not change, depending on which line is out of service. These required RAS changes would be a functional modification.

Any functional modification to a RAS will need to be reviewed and approved through the process described in Requirements R1, R2, and R3. The need for ~~review are~~such functional ~~modifications. RAS~~ modifications may be identified ~~by a CAP pursuant to Requirement R6 beyond the substitution of components that merely preserve the original functionality are functional~~ in several ways including but not limited to the Planning evaluations pursuant to R4, incorrect operations pursuant to R5, a test failure pursuant to R8, or Planning assessments related to future additions or modifications~~. RAS removal is essentially a form of RAS functional modification. Any RAS proposed for removal needs to be evaluated under the RAS Retirement section of the Attachment 1 checklist.~~

of other facilities.

To facilitate a review that promotes reliability, the RAS-entity(ies) must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity(ies) provide them to the reviewing Reliability Coordinator (RC). The RC that coordinates the area where the RAS is located is responsible for the review. In cases where a RAS crosses multiple RC Area boundaries, each affected RC is responsible for conducting either individual reviews or a coordinated review.

Requirement R1 does not specify how far in advance of implementation the RAS-entity(ies) must provide Attachment 1 data to the reviewing RC. The information will need to be submitted early enough to allow RC review in the allotted time pursuant to Requirement R2, including resolution of any reliability issues that might be identified, in order to obtain approval of the reviewing RC. Expeditious submittal of this information is in the interest of each RAS-~~owner~~entity to effect a timely implementation.

Requirement R2

Requirement R2 mandates that the RC perform reviews of all proposed new RAS and existing RAS proposed for functional modification, or retirement (removal from service) in its RC Area.

RAS are unique and customized assemblages of protection and control equipment. As such, they have a potential to introduce reliability risks to the BES, if not carefully planned, designed, and installed. ~~-~~A RAS may be installed to address a reliability issue, or achieve an economic or operational advantage, and could introduce reliability risks that might not be apparent to a RAS-~~owner(s).~~ entity(ies). An independent review by a multi-disciplinary panel of subject matter experts with planning, operations, protection, telecommunications, and equipment expertise is an effective means of identifying risks and recommending RAS modifications when necessary.

The RC is the functional entity best suited to perform the RAS reviews because it 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~~ facilitates the evaluation of interactions among separate RAS as well as interactions among the 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, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC may request assistance in RAS reviews from other parties such as the PC(s) or regional technical groups (e.g., Regional Entities); however, the RC retains responsibility for compliance with the requirement.

It is recognized that the RC does not possesses more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not contain compliance requirements. If Reliability Standards address functions that are not described in the model, the Reliability Standard requirements take precedence over the Functional Model. For further reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

Attachment 2 of this standard is a checklist for assisting the RC in identifying design and implementation aspects of a RAS, and for facilitating consistent reviews of each RAS submitted ~~RAS~~ for review. The time frame of four~~-~~ full~~-~~ calendar months is consistent with current utility practice; however, flexibility is provided by allowing the parties to negotiate a different schedule for the review. Note, an RC may need to include this task in its reliability plan(s) for the NERC Region(s) in which it is located.

Requirement R3

Requirement R3 mandates that ~~the~~each RAS-entity ~~address~~resolve all reliability issues (pertaining to its RAS) identified ~~by the reviewing RC~~ during the RAS review~~, and obtain approval from the reviewing RC that the RAS implementation can proceed. The review by the RC is intended to identify reliability issues that must be resolved before the RAS can be put in service.~~ by the reviewing Reliability Coordinators. Examples of reliability issues include a lack of dependability, security, or coordination. RC approval of a RAS is considered to be obtained when the reviewing RC's feedback to each RAS-entity indicates that either no reliability issues were identified during the review or all identified reliability issues were resolved to the RC's satisfaction.

Dependability is a component of reliability ~~and~~that is the measure of certainty of a device to operate when required. If a RAS is installed to meet performance requirements of NERC Reliability Standards, a failure of the RAS to operate when intended would put the System at risk of violating NERC Reliability Standards if specified Contingency(ies) or System conditions occur. This risk is mitigated by designing the RAS so that it will accomplish the intended purpose while experiencing a single RAS component failure. This is often accomplished through redundancy. Other strategies for providing dependability include "over-tripping" load or generation, or alternative automatic backup schemes.

Security is a component of reliability ~~and~~that is the measure of certainty of a device to not operate inadvertently. False or inadvertent operation of a RAS results in taking a programmed action without the appropriate arming conditions, occurrence of specified Contingency(ies), or System conditions expected to trigger the RAS action. Typical RAS actions include shedding load or generation or re-configuring the System. Such actions, if inadvertently taken, are undesirable and may put the System in a less secure state. Worst case impacts from inadvertent operation often occur if all programmed RAS actions occur. If the System performance still satisfies PRC-012-2 Requirement R4, Part 4.3, no additional mitigation is required. ~~-~~Security enhancements to the RAS design, such as voting schemes, are acceptable mitigations against inadvertent operations.

Any reliability issue identified during the review must be resolved before implementing the RAS to avoid placing the System at unacceptable risk. The RAS-entity ~~(and any other RAS-owner)~~ or the reviewing RC(s) may have alternative ideas or methods available to resolve the issue(s). In either case, the concern needs to be resolved in deference to reliability, and the RC has the final decision.

A specific time period for the RAS-entity to respond to the RC(s) review is not necessary because an expeditious response is in the interest of each RAS-~~owner~~entity to effect a timely implementation.

Requirement R4

Requirement R4 mandates that an evaluation of each RAS be performed at least once every 60~~-~~ full~~-~~ calendar months. The purpose of a periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that requirements for BES performance following inadvertent RAS operation and single component failure continue to be satisfied. A periodic evaluation is required because changes in ~~system~~System topology or operating conditions ~~that have occurred since the previous RAS evaluation (or initial review)~~ may change the effectiveness of a RAS or the way it interacts with and impacts the BES.

~~A period~~ Requirement R4 also clarifies that the RAS single component failure and inadvertent operation tests do not apply to RAS which are determined to be limited impact. Requiring a limited impact RAS to meet the single component failure and inadvertent operation tests would just add complexity to the design with little or no improvement in the reliability of the BES.

For existing RAS, the initial performance of Requirement R4 must be completed within sixty~~-~~ full~~-~~ calendar months of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within sixty full calendar months of the RAS approval date by the reviewing RC(s). Sixty full calendar months was selected as the maximum time frame between evaluations based on the time frames for similar requirements in ~~NERC~~ Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation ~~should~~can be performed sooner if it is determined that material changes to System topology or System operating conditions ~~that~~ could potentially impact the effectiveness or coordination of the RAS ~~have occurred since the previous RAS evaluation or will occur before the next scheduled evaluation.~~. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluations (Requirement R4, Parts 4.1.1 through 4.1.4) are planning analyses that may involve modeling of the interconnected transmission system to assess BES performance~~; consequently, the TP~~. The PC is the functional entity best suited to perform the analyses~~.~~ because they have a wide-area planning perspective. To promote reliability, the ~~TP~~PC is required to provide the ~~RAS-owner(s) and the reviewing RC(s) with the~~ results of ~~each~~the evaluation~~.~~

to each RAS-entity and reviewing RC, as well as each impacted Planning Coordinator and Transmission Planner.

The intent of Requirement R4, Part 4.1.3 is to require that the possible inadvertent operation of the RAS~~,~~ (other than limited impact RAS), caused by the malfunction of a single component of the RAS, meet the same System performance requirements as those required for the Contingency(ies) or System conditions for which it is designed. If the RAS is designed to meet one of the planning events (P0-P7) in TPL-001-4, the possible inadvertent operation of the RAS must meet the same performance requirements listed in the standard for that planning event.

The requirement clarifies that the inadvertent operation to be considered is only that caused by the malfunction of a single RAS component. This allows features to be designed into the RAS to improve security, such that inadvertent operation due to malfunction of a single component is prevented~~ or else~~; otherwise, the RAS inadvertent operation ~~satisfies~~must satisfy Requirement R4, Part 4.1.3.

The intent of Requirement R4, Part 4.1.3 is also to require that the possible inadvertent operation of the RAS (other than limited impact RAS) installed for an extreme event in TPL-001-4 or for some other Contingency or System conditions not defined in TPL-001-4 (therefore without performance requirements), meet the minimum System performance requirements of Category P7 in Table 1 of NERC Reliability Standard TPL-001-4. However, instead of referring to the TPL standard, the requirement lists the System performance requirements that a potential inadvertent operation must satisfy. The performance requirements listed (Requirement R4, Parts 4.1.3.1 – 4.1.3.5) are the ones that are common to all planning events (P0-P7) listed in TPL-001-4.

With reference to Requirement 4, Part 4.1.3, note that the only differences in performance requirements among the TPL (P0-P7) events (not common to all of them) concern Non-Consequential Load Loss and interruption of Firm Transmission Service. ~~Performance~~It is not necessary for Requirement R4, Part 4.1.3 to specify performance requirements ~~in~~related to these areas ~~are not relevant. A~~because a RAS is only allowed to drop non-consequential load or interrupt Firm Transmission Service~~ can do that only~~ if that action is allowed for the Contingency for which it is designed. Therefore, the inadvertent operation should automatically meet Non-Consequential Load Loss or interrupting Firm Transmission Service performance requirements for the Contingency(ies) for which it was designed.

Part 4.1.4 requires that a single component failure in the RAS~~,~~ (other than limited impact 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 is designed. This analysis is needed to ensure that changing System conditions do not result in the single component failure requirement not being met.

Requirements for inadvertent RAS operation (Requirement R4, Part 4.1.3) and single component failure (Requirement R4, Part 4.1.4) are reviewed by the reviewing RC(s) before a new or functionally modified RAS is placed in~~-~~-service, and are typically satisfied by specific design considerations. Although the scope of the periodic evaluation does not include a new design review, it is possible that a design which previously satisfied requirements for inadvertent RAS operation and single component failure may fail to satisfy these requirements at a later ~~point in~~ time, and must be evaluated with respect to the current System. For example, if the actions of a particular RAS include tripping load, ~~System changes~~load growth could occur over time that ~~impact~~impacts the amount of load ~~originally~~to be tripped ~~by a particular RAS output.~~. These changes could result in ~~inadvertent activation of that output, therefore,~~ tripping too much load upon inadvertent operation and result in violations of Facility Ratings. Alternatively, the RAS might be designed to trip more load than necessary (i.e., "over trip") in order to satisfy single~~-~~ component~~-~~ failure requirements. ~~-~~System changes could result in too little load being tripped ~~at affected locations and result in~~and unacceptable BES performance if one of the loads failed to trip.

~~Requirement R5~~

Requirement R5

The correct operation of a RAS is important to maintain the reliability and integrity of the BES. Any incorrect operation of a RAS indicates the RAS effectiveness and/or coordination may have been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: (1) verify RAS operation is consistent with implemented design; or (2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120~~-~~ full calendar day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation~~.~~; however, flexibility is provided by allowing the parties to negotiate a different schedule for the analysis. To promote reliability, the RAS-~~owner~~entity(s) is required to provide the results of RAS operational performance analyses to its reviewing RC(s).

The RAS-~~owner(s~~entity(ies) may need to collaborate with ~~their~~its associated ~~TP~~Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation ~~triggers and responds (Parts~~was triggered correctly (Part 5.1~~,~~.1), responded as designed (Part 5.1.2~~)~~), and that the resulting BES response (Parts 5.1.3~~,~~ and 5.1.4) ~~is~~was consistent with the intended functionality and design of the RAS. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate on the operational performance analysis.

Requirement R6

~~Deficiencies~~ RAS deficiencies potentially pose a reliability risk to the BES. RAS deficiencies may be identified ~~either~~ in the periodic RAS evaluation conducted by the ~~TP~~PC in Requirement R4, ~~or~~ in the operational analysis conducted by the RAS-~~owner(s) pursuant to~~ entity in Requirement R5, ~~are likely to pose a reliability risk to the BES.~~ or in the functional test performed by the RAS-entity(ies) in Requirement R8. To mitigate ~~this~~potential reliability ~~risk~~risks, Requirement R6 mandates that each RAS-~~owner develop~~ entity participate in developing a CAP that establishes the mitigation actions and timetable necessary to address the deficiency.

The RAS-entity(ies) that owns the RAS components, is responsible for the RAS equipment, and is in the best position to develop the timelines and perform the necessary work to correct RAS deficiencies. If necessary, the RAS-entity(ies) may request assistance with development of the CAP ~~requires that a~~from other parties such as its Transmission Planner or Planning Coordinator; however, the RAS-entity has the responsibility for compliance with this requirement.

A CAP may require functional ~~change~~changes be made to a RAS. In this case, Attachment 1 information must be submitted to the reviewing RC(s~~) prior~~), an RC review must be performed to ~~placing~~obtain RC approval before the RAS-entity can place RAS modifications in~~-~~-service, per ~~Requirement~~Requirements R1~~.~~

, R2, and R3.

Depending on the complexity of the issues, development of a CAP may require study, engineering~~,~~ or consulting work. A timeframe of six~~-~~ full~~-~~ calendar months is allotted to allow enough time for RAS-~~owner~~entity collaboration on the CAP development, while ensuring that deficiencies are addressed in a reasonable time. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the RAS deficiency is resolved. ~~Such~~The possibility of such operating restrictions will incent the RAS-~~owner~~entity to resolve the issue as quickly as possible~~.~~

~~A CAP documents a RAS performance deficiency, the actions to correct the deficiency with identified tasks, and the time frame for completion~~.

The following are example situations of when a CAP is required:

- A determination after a RAS operation/non-operation investigation that the RAS did not meet performance expectations~~. The RAS~~ or did not operate as designed.
- Periodic planning assessment reveals RAS changes are necessary to correct performance or coordination issues.
- Equipment failures.
- Functional testing identifies that a RAS is not operating as designed.

Requirement R7

~~Implementation of a CAP ensures~~Requirement R7 mandates that each RAS-entity implement its CAP developed in Requirement R6 which mitigates the deficiencies ~~are corrected by following a documented timetable of~~ identified in Requirements R4, R5, or R8. By definition, a CAP is: "A list of actions~~. If necessary, the~~ and an associated timetable for implementation to remedy a specific problem."

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. ~~Operating restrictions imposed by the RC~~ If the CAP is changed, the RAS-entity must notify the reviewing Reliability Coordinator(s). The RAS-entity must also ~~incents RAS-owners to mitigate the issues and provide assurance that implementation is~~ notify the Reliability Coordinator(s) when the CAP has been completed.

The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions will incent the RAS-entity to complete the CAP as quickly as possible.

Requirement R8

The reliability objective of Requirement R8 is to test the non-Protection System components of a RAS (controllers such as programmable logic controllers (PLCs)) and to verify the overall performance of the RAS through functional testing. Functional tests validate RAS operation by ensuring System states are detected and processed, and that actions taken by the controls are correct and occur within the expected time using the in-service settings and logic. Functional testing is aimed at assuring overall RAS performance and not the component focused testing contained in the PRC-005 maintenance standard.

Since the functional test operates the RAS under controlled conditions with known System states and expected results, testing and analysis can be performed ~~without~~with minimum impact to the BES and should align with expected results. The RAS-~~owner~~entity is in the best position to determine the testing procedure and schedule due to their overall knowledge of the RAS design, installation, and functionality. Periodic testing provides the RAS-~~owner~~entity assurance that latent failures may be identified and also promotes identification of changes in the System that may have introduced latent failures.

~~While the~~

The six~~-~~ and twelve full calendar~~-~~ year functional testing ~~interval is~~intervals are greater than the annual or bi-annual periodic testing performed in some NERC Regions~~, the drafting team selected it because it is consistent with some of the maintenance intervals of various Protection System and Automatic Reclosing components established in PRC-005. Consequently, this interval provides entities the opportunity to design their RAS functional testing programs such that it coincides with the testing of any associated PRC-005 components. The six-calendar-year interval is~~. However, these intervals are a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS.

Longer test intervals for limited impact RAS are acceptable because incorrect operations or failures to operate present a low reliability risk to the Bulk Power System.

Functional testing is not synonymous with end-to-end testing. End-to-end testing is an acceptable method but ~~it~~ may not be feasible for many RAS. When end-to-end testing is not possible, a RAS-~~owner~~entity may use a segmented functional testing approach. The segments can be tested individually negating the need for complex maintenance schedules. In addition, actual RAS operation(s) can be used to fulfill the functional testing requirement. If a RAS does not operate in its entirety during a System event or System conditions do not allow an end-to-end ~~system~~scheme test~~—the~~, then the segmented approach should be used to fulfill this Requirement. Functional testing includes the testing of all RAS inputs used for detection, arming, operating, and data collection. Functional testing also includes the processing ~~by the~~ logic and infrastructure of a RAS as well as the action initiation by RAS outputs to address the System condition(s) for which the RAS is designed. All segments and components of a RAS must be tested or have proven operations within ~~a six-calendar-year interval to demonstrate compliance with the Requirement.~~

~~As an example, consider a RAS implemented with one PLC that senses System conditions such as loading and line status from many locations. At one of these locations, a line protective relay (a component of a Protection System and included in the Protection System Maintenance Program (PSMP) of a RAS-owner) receives commands from the RAS PLC and sends data over non-Protection System communications infrastructure to operate a breaker. A functional test would send signals of simulated System conditions to the PLC to initiate an operate command to the protective relay, thus operating its associated breaker. This action verifies RAS action, verifies PLC control logic, and verifies RAS communications from PLC to relay. To complete this portion of a functional test, application of external testing signals to the protective relay, verified at the PLC are necessary to confirm full functioning of the RAS segment being tested. This example describes a test for one segment of the RAS, the remaining segments would also require testing~~the applicable maximum test interval to demonstrate compliance with the Requirement.

As an example of segment testing, consider a RAS controller implemented using a PLC that receives System data, such as loading or line status, from distributed devices. These distributed devices could include meters, protective relays, or other PLCs. In this example RAS, a line protective relay is used to provide an analog metering quantity to the RAS control PLC. A functional test would verify that the System data is received from the protective relay by the PLC, processed by the PLC, and that PLC outputs are appropriate. There is no need to verify the protective relay's ability to measure the power system quantities, as this is a requirement for Protection Systems used as RAS in PRC-005, Table 1-1, Component Type – Protective Relay. Rather the functional test is focused on the use of the protective relay data at the PLC, including the communications data path from relay to PLC if this data is essential for proper RAS operation. Additionally, if the control signal back to the protective relay is also critical to the proper functioning of this example RAS, then that path is also verified up-to the protective relay. This example describes a test for one segment of a RAS which verifies RAS action, verifies PLC control logic, and verifies RAS communications.

IEEE C37.233, "IEEE Guide for Power System Protection Testing," 2009 section 8 (particularly 8.3-8.5), provides an overview of functional testing. ~~-~~The following opens section 8.3:

> Proper implementation requires a well-defined and coordinated test plan for performance evaluation of the overall system during agreed maintenance intervals. The maintenance test plan, also referred to as functional system testing, should include inputs, outputs, communication, logic, and throughput timing tests. The functional tests are generally not component-level testing, rather overall system testing. Some of the input tests may need to be done ahead of overall system testing to the extent that the tests affect the overall performance. The test coordinator or coordinators need to have full knowledge of the intent of the scheme, isolation points, simulation scenarios, and restoration to normal procedures.

> The concept is to validate the overall performance of the scheme, including the logic where applicable, to validate the overall throughput times against system modeling for different types of ~~contingencies~~Contingencies, and to verify scheme performance as well as the inputs and outputs.

If a RAS passes a functional test, it is not necessary to provide that specific information to the RC because that is the expected result and requires no further action. If a segment of a RAS fails a functional test, the status of that degraded RAS is required to be reported (in Real-time) to the Transmission Operator via PRC-001, Requirement R6, then to the RC via TOP-001-~~2, Requirement R5.~~3, Requirement R8. See Phase 2 of Project 2007-06 for the mapping document from PRC-001 to other standards regarding notification of RC by TOP if a deficiency is found during testing. Consequently, it is not necessary to include a similar requirement in this standard.

The initial test interval begins on the effective date of the standard pursuant to the implementation plan. Subsequently, the maximum allowable interval between functional tests is six full calendar years for RAS that are not designated as limited impact RAS and twelve full calendar years for RAS that are designated as limited impact RAS. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. A RAS-entity may choose to count a correct RAS operation as a qualifying functional test for those RAS segments which operate. If a System event causes a correct, but partial RAS operation, separate functional tests of the segments that did not operate are still required within the maximum test interval that started on the date of the previous successful test of those (non-operating) segments in order to be compliant with Requirement R8.

Requirement R9

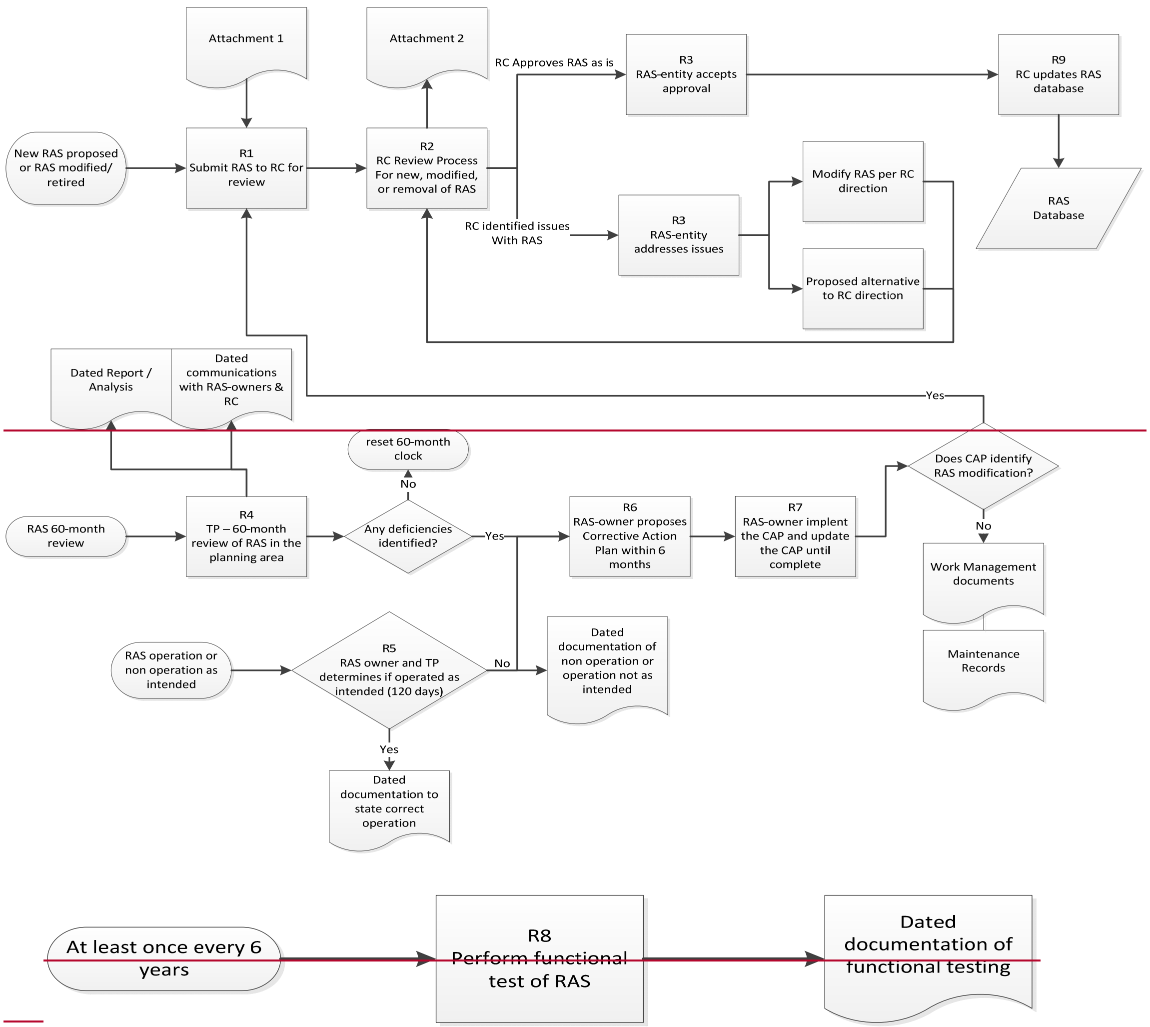
The RAS database required to be maintained by the RC in Requirement R9 ensures information regarding existing RAS is available to entities with a potential reliability need. Attachment 3 contains the minimum information that is required to be included about each RAS listed in the database. Additional information can be requested by the RC.

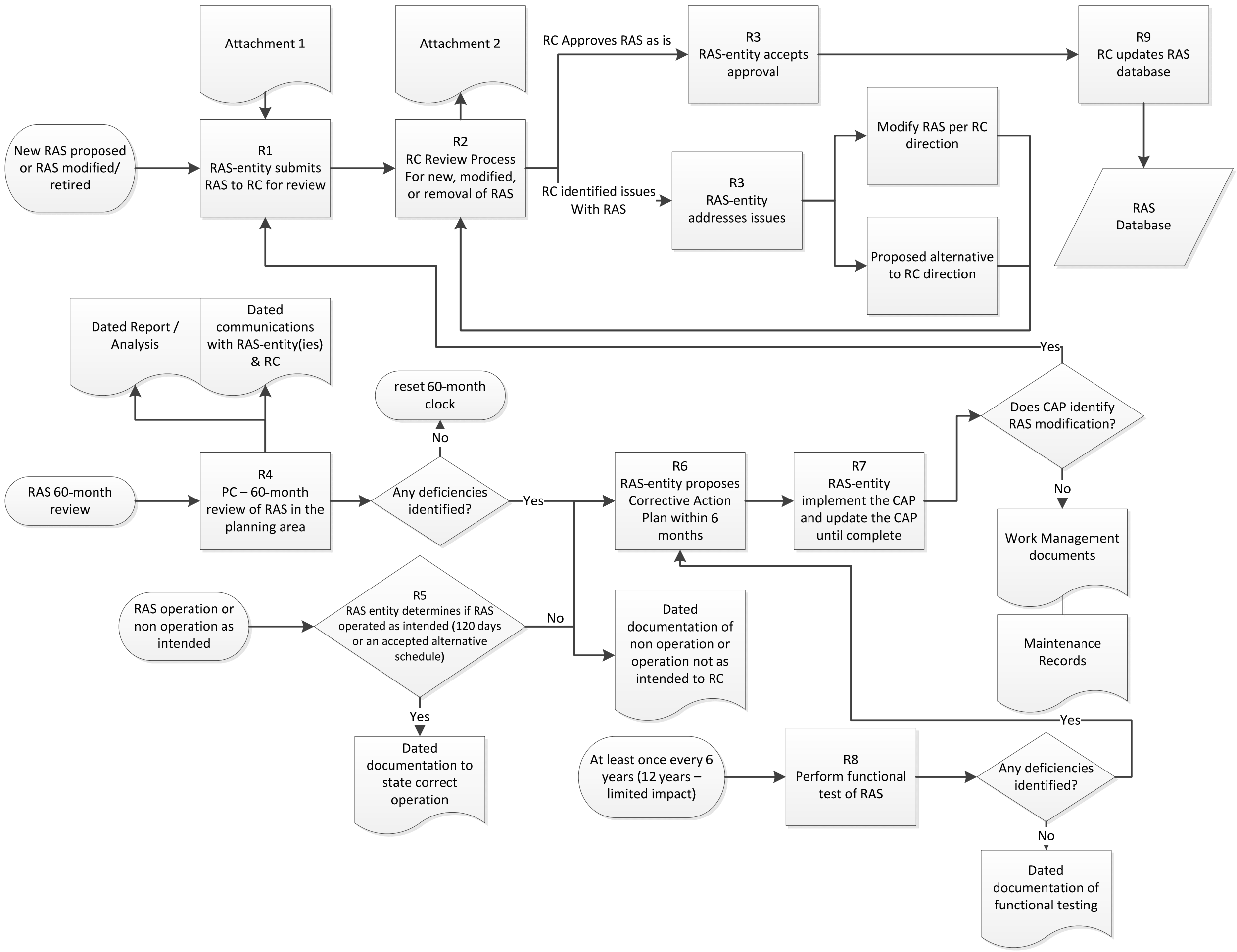
The information provided is sufficient for an entity with a reliability need to evaluate whether the RAS can impact its System. For example, a RAS performing generation rejection to mitigate an overload on a transmission line may cause a power flow change within an adjacent entity area. This entity should be able to evaluate the risk that a RAS poses to its System from the high-level information provided in the RAS database.

The RAS database does not need to list detailed settings or modeling information, but the description of the System performance issues, System conditions, and the intended corrective actions must be included. If additional details about the RAS operation are required, the entity may obtain the contact information of the RAS-entity from the RC.

Process Flow Diagram

The ~~following diagrams depict~~diagram below depicts the process flow of the PRC-012-2 requirements.




Attachment 1
Attachment 2
RC Approves RAS as is
R3
RAS-entity accepts approval
R9
RC updates RAS database
Modify RAS per RC direction
New RAS proposed or RAS modified/ retired
R1
RAS-entity submits RAS to RC for review
R2
RC Review Process For new, modified, or removal of RAS
RC identified issues With RAS
R3
RAS-entity addresses issues
RAS Database
Proposed alternative to RC direction
Dated Report / Analysis
Dated communications with RAS-entity(ies) & RC
Yes
reset 60-month clock
Does CAP identify RAS modification?
No
RAS 60-month review
R4
PC – 60-month review of RAS in the planning area
Any deficiencies identified?
Yes
R6
RAS-entity proposes Corrective Action Plan within 6 months
R7
RAS-entity implement the CAP and update the CAP until complete
No
Work Management documents
RAS operation or non operation as intended
R5
RAS entity determines if RAS operated as intended (120 days or an accepted alternative schedule)
No
Dated documentation of non operation or operation not as intended to RC
Maintenance Records
Yes
Yes
Dated documentation to state correct operation
At least once every 6 years (12 years – limited impact)
R8
Perform functional test of RAS
Any deficiencies identified?
No
Dated documentation of functional testing

Technical Justifications for Attachment 1 Content
Supporting Documentation for RAS Review

To perform an adequate review of the expected reliability implications of a Remedial Action Scheme (RAS), it is necessary for the RAS-~~owner(s~~entity(ies) to provide a detailed list of information describing the RAS to the ~~designated RAS-entity.~~reviewing RC. If there are multiple ~~owners of the~~RAS-entities for a single RAS, information ~~may~~will be needed from all ~~owners, but a single~~ RAS-~~owner (designated as the~~ entities. Ideally, in such cases, a single RAS-entity~~) is assigned~~ will take the ~~responsibility of compiling~~lead to compile all the ~~RAS~~ data ~~and presenting it to the reviewing RC(s). Other RAS-owners may participate in the review, if they choose.~~ identified into a single Attachment 1.

The necessary data ranges from a general overview of the RAS to summarized results of transmission planning studies, to information about hardware used to implement the RAS. Coordination between the RAS and other RAS and protection and control systems will be examined for possible adverse interactions. This review can include wide-ranging electrical design issues involving the specific hardware, logic, telecommunications, and other relevant equipment and controls that make up the RAS.

Attachment 1

The following checklist identifies important RAS information for each new or functionally modified[7] RAS that the RAS-entity shall document and provide to the RC for review pursuant to Requirement R1. When a RAS has been previously reviewed, only the proposed modifications to that RAS require review; however, it will be helpful to each reviewing RC if the RAS-entity provides a summary of the ~~previously approved~~existing RAS functionality.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.

   Provide a description of the RAS to give an overall understanding of the functionality and a map showing the location of the RAS. Identify other protection and control systems requiring coordination with the RAS. See RAS Design below for additional information.

   Provide a single-line drawing(s) showing all sites involved. The drawing(s) should provide sufficient information to allow the RC review team to assess design reliability, and should include information such as the bus arrangement, circuit breakers, the

[7] Functionally Modified: Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond ~~the~~in-kind replacement of existing components ~~that preserve the original functionality is a functional modification.~~
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels; i.e., addition or removal

associated switches, etc. For each site, indicate whether detection, logic, action, or a combination of these is present.

2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.

3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP. [Reference NERC Reliability Standard PRC-012-2, Requirements R5 and R7]

   Provide a description of any functional modifications to a RAS that are part of a CAP that are proposed to address performance deficiency(ies) identified in the periodic evaluation pursuant to Requirement R4, ~~or~~ the analysis of an actual RAS operation pursuant to Requirement R5, or functional test failure pursuant to Requirement R8. A copy of the most recent CAP must be submitted in addition to the other data specified in Attachment 1.

4. Initial data to populate the RAS database.

   a. RAS name

   b. Each RAS-entity and contact information

   c. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent 60-full-calendar-month (Requirement R4) evaluation date; and, date of retirement, if applicable

   d. System performance issue or reason for installing the RAS (*e.g.*, thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery)

   e. Description of the ~~contingencies~~Contingencies or System conditions for which the RAS was designed (initiating conditions)

   f. Corrective action taken by the RAS

   g. Identification of limited impact[8] RAS

   ~~g.~~h. Any additional explanation relevant to high level understanding of the RAS

   Note: This is the same information as is identified in Attachment 3. Supplying the data at this point in the review process ensures a more complete review and minimizes any administrative burden on the reviewing RC(s).

~~II. Functional Description and Transmission Planning Information~~

~~1. Contingencies and system conditions that the RAS is intended to remedy. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.1]~~

II. Functional Description and Transmission Planning Information

1. Contingencies and System conditions that the RAS is intended to remedy. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.1]

[8] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. See Attachment 2 for a description of the limited impact determination by the Reliability Coordinator. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.

a. The System conditions that would result if no RAS action occurred should be identified.

b. Include a description of the System conditions that should arm the RAS so as to be ready to take action upon subsequent occurrence of the critical ~~system contingencies~~System Contingencies or other operating conditions when RAS action is intended to occur. If no arming conditions are required, this should also be stated.

c. Event-based RAS are triggered by specific ~~contingencies~~Contingencies that initiate mitigating action. ~~-~~Condition-based RAS may also be initiated by specific ~~contingencies~~Contingencies, but specific Contingencies are not always required. These triggering Contingencies and/or conditions should be identified.

2. The actions to be taken by the RAS in response to disturbance conditions. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.2]

   Mitigating actions are designed to result in acceptable System performance. ~~-~~These actions should be identified, including any time constraints and/or "backup" mitigating measures that may be required in case of a single RAS component failure.

3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), ~~system~~System conditions, and ~~contingencies~~Contingencies analyzed on which the RAS design is based, and when those technical studies were performed. [Reference NEC Reliability Standard PRC-014, R3.2]

   Review the scheme purpose and impact to ensure it is (still) necessary, serves the intended purposes, and meets current performance requirements. ~~-~~While copies of the full, detailed studies may not be necessary, any abbreviated descriptions of the studies must be detailed enough to allow the reviewing RC(s) to be convinced of the need for the scheme and the results of RAS-related operations.

~~4. Information regarding any future system plans that will impact the RAS. [Reference NERC Reliability Standard PRC-014, R3.2]~~

4. Information regarding any future System plans that will impact the RAS. [Reference NERC Reliability Standard PRC-014, R3.2]

   The RC's other responsibilities under the NERC Reliability Standards focus on the Operating Horizon, rather than the Planning Horizon. As such, the RC is less likely to be aware of any longer range plans that may have an impact on the proposed RAS. Such knowledge of future Plans is helpful to provide perspective on the capabilities of the RAS.

~~5. Documentation showing that the possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following: [Reference NERC Reliability Standard PRC-012, R1.4]~~

5. RAS-entity proposed designation as "limited impact" or not.

   A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact for the purposes of Requirement 4, Parts 4.1.3 and 4.1.4.

   ~~a. The BES shall remain stable.~~

   ~~b.~~a. ~~Cascading shall not occur.~~

   ~~c.~~a. ~~Applicable Facility Ratings shall not be exceeded.~~

~~d.~~a. ~~BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.~~

~~e.~~a.~~Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.~~

6. Documentation showing that the possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following: [Reference NERC Reliability Standard PRC-012, R1.4]
    a. The BES shall remain stable.
    b. Cascading shall not occur.
    c. Applicable Facility Ratings shall not be exceeded.
    d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.
    e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

~~6.~~7. An evaluation indicating that the RAS settings and operation avoids adverse interactions with other RAS, and protection and control systems. [Reference NERC Reliability Standards PRC-012, R1.5 and PRC-014, R3.4]

    RAS are complex schemes that may take action such as tripping load or generation or re-configuring the ~~system~~System. Many RAS depend on sensing specific System configurations to determine whether they need to arm or take actions. An examples of an adverse interaction: A RAS that reconfigures the System also changes the available fault duty, which can affect distance relay overcurrent (“fault detector”) supervision and ground overcurrent protection coordination.

~~7.~~8. Identification of other affected RCs.

    This information is needed to aid in information exchange among all affected entities and coordination of the RAS with other RAS and protection and control systems.

III. Implementation

1. Documentation describing the applicable equipment used for detection, ~~telecommunications, transfer trip~~dc supply, communications, logic processing, control actions, and monitoring.

Detection

Detection and initiating devices, whether for arming or triggering action, should be designed to be secure. Several types of devices have been commonly used as disturbance, condition, or status detectors:

- Line open status (event detectors),
- Protective relay inputs and outputs (event and parameter detectors),
- Transducer and IED (analog) inputs (parameter and response detectors),
- Rate of change (parameter and response detectors).

DC Supply

Batteries and charges, or other forms of dc supply for RAS, are commonly also used for Protection Systems. This is acceptable, and maintenance of such supplies is covered by PRC-005. However, redundant RAS systems, when used, should be supplied from separately protected (fused or breakered) circuits.

Communications: Telecommunications Channels and Transfer Trip Equipment

Telecommunications channels used for sending and receiving RAS information between sites and/or transfer trip devices should meet at least the same criteria as other relaying protection communication channels. Discuss performance of any non-deterministic communication systems used (such as Ethernet).

The scheme logic should be designed so that loss of the channel, noise, or other channel or equipment failure will not result in a false operation of the scheme.

It is highly desirable that the channel equipment and communications media (power line carrier, microwave, optical fiber, etc.) be owned and maintained by the RAS-~~owner~~entity, or perhaps leased from another entity familiar with the necessary reliability requirements. All channel equipment should be monitored and alarmed to the dispatch center so that timely diagnostic and repair action shall take place upon failure. Publicly switched telephone networks are generally an undesirable option.

Communication channels should be well labeled or identified so that the personnel working on the channel can readily identify the proper circuit. Channels between entities should be identified with a common name at all terminals.

Transfer trip equipment, when separate from other RAS equipment, should be monitored and labeled similarly to the channel equipment.

Logic Processing

All RAS require some form of logic processing to determine the action to take when the scheme is triggered. Required actions are always scheme dependent. Different actions may be required at different arming levels or for different ~~contingencies.~~ Contingencies. Scheme logic may be achievable by something as simple as wiring a few auxiliary relay contacts or by much more complex logic processing.

Platforms that have been used reliably and successfully include PLCs in various forms, personal computers (PCs), microprocessor protective relays, remote terminal units (RTUs), and logic processors. Single-function relays have been used historically to implement RAS, but this approach is now less common except for very simple new RAS or minor additions to existing RAS.

Control Actions

RAS action devices may include a variety of equipment such as transfer trip, protective relays, and other control devices. These devices receive commands from the logic processing function (perhaps through telecommunication facilities) and initiate RAS actions at the sites where action is required.

Monitoring by SCADA/EMS should include at least

- Whether the scheme is in-service or out of service.
  - For RAS that are armed manually, the arming status may be the same as whether the RAS is in-service or out of service.
  - For RAS that are armed automatically, these two states are independent because a RAS that has been placed in~~-~~-service may be armed or unarmed based on whether the automatic arming criteria have been met.
- The current operational state of the scheme (available or not).
- In cases where the RAS requires single~~-~~ component failure performance ~~(~~; e.g., redundancy~~)~~,, the minimal status indications should be provided separately for each system.
  - The minimum status is generally sufficient for operational purposes; however, where possible it ~~may be~~is often useful to provide additional information regarding partial failures or the status of critical components to allow the RAS-~~owner~~entity to more efficiently troubleshoot a reported failure. Whether this capability exists will depend in part on the design and vintage of equipment used in the RAS. While all schemes should provide the minimum level of monitoring, new schemes should be designed with the objective of providing monitoring at least similar to what is provided for microprocessor-based Protection Systems.

2. Information on detection logic and settings/parameters that control the operation of the RAS. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.3]

   Several methods to determine line or other equipment status are in common use, often in combination:

   a. Auxiliary switch contacts from circuit breakers and disconnect switches (52a/b, 89a/b)—the most common status monitor; “a” contacts exactly emulate actual breaker status, while “b” contacts are opposite to the status of the breaker;

   b. Undercurrent detection—a low level indicates an open condition, including at the far end of a line; pickup is typically slightly above the total line-charging current;

   c. Breaker trip coil current monitoring—typically used when high-speed RAS response is required, but usually in combination with auxiliary switch contacts and/or other detection because the trip coil current ceases when the breaker opens; and

d. Other detectors such as angle, voltage, power, frequency, rate of change of ~~these~~the aforementioned, out of step, etc~~. — very~~. are dependent on specific scheme requirements, but some forms may substitute for or enhance ~~current~~other monitoring ~~detection~~described in items ‘a’, ‘b’, and ‘c’ above.

Both RAS arming and action triggers often require monitoring of analog quantities such as power, current, and voltage at one or more locations and are set to detect a specific level of the pertinent quantity. -These monitors may be relays, meters, transducers, or other devices

3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in~~-~~-service or is being maintained.

   In this context, a multifunction device (e.g., microprocessor-based relay) is a single component that is used to perform the function of a RAS in addition to protective relaying and/or SCADA simultaneously. It is important that other applications in the multifunction device do not compromise the functionality of the RAS when the device is in service or when it is being maintained. The following list outlines considerations when the RAS function is applied in the same microprocessor-based relay as equipment protection functions:

   a. Describe how the multifunction device is applied in the RAS.

   b. Show the general arrangement and describe how the multi-function device is labeled in the design and application, so as to identify the RAS and other device functions.

   c. Describe the procedures used to isolate the RAS function from other functions in the device.

   d. Describe the procedures used when each multifunction device is removed from service and whether coordination with other protection schemes is required.

   e. Describe how each multifunction device is tested, both for commissioning and during periodic maintenance testing, with regard to each function of the device.

   f. Describe how overall periodic RAS functional and throughput tests are performed if multifunction devices are used for both local protection and RAS.

   g. Describe how upgrades to the multifunction device, such as firmware upgrades, are accomplished. How is the RAS function taken into consideration?

   Other devices that are usually not considered multifunction devices such as auxiliary relays, control switches, and instrument transformers may serve multiple purposes such as protection and RAS. Similar concerns apply for these applications as noted above.

4. Documentation ~~showing that~~ describing the System performance resulting from a single~~-~~ component failure in ~~a~~the RAS, except for limited impact RAS, when the RAS is intended to operate~~, does~~. A single component failure in a RAS not determined to be limited impact must 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 is designed. The documentation should describe or illustrate how the ~~implementation~~ design achieves this objective. [Reference NERC Reliability Standard PRC-012, R1.3]

   RAS automatic arming, if applicable, is vital to RAS and System performance and is therefore included in this requirement. Acceptable methods to achieve this objective include, but are not limited to the following:

   ~~Acceptable methods to achieve this objective include the following:~~

   a. Providing redundancy of RAS components. Typical examples are listed below:

      i. Protective or auxiliary relays used by the RAS.

      ii. Communications systems necessary for correct operation of the RAS.

      iii. Sensing devices used to measure electrical or other quantities used by the RAS.

      iv. Station dc supply associated with RAS functions.

      v. Control circuitry associated with RAS functions through the trip coil(s) of the circuit breakers or other interrupting devices.

      ~~vi. Computers or programmable logic devices used to analyze information and provide RAS operational output.~~

      vi. Logic processing devices that accept System inputs from RAS components or other sources, make decisions based on those inputs, or initiate output signals to take remedial actions.

   b. 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~~due to that single component failure will still result in satisfactory System performance, as long as tripping the total armed amount of load or generation does not cause other adverse impacts to reliability.

   c. Using alternative automatic actions to back up failures of single RAS components.

   d. 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.

5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies important RAS information for each existing RAS to be retired that the RAS-entity shall document and provide to the Reliability Coordinator for review pursuant to Requirement R1.

1. Information necessary to ensure that the Reliability Coordinator is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of technical studies, if applicable, upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

   While the documentation necessary to evaluate RAS removals is not as extensive as for new or functionally modified RAS, it is still vital that, when the RAS is no longer available, System performance will still meet the appropriate (usually TPL) requirements for the Contingencies or System conditions that the RAS had been installed to remediate.

Technical Justification for Attachment 2 Content

Reliability Coordinator RAS Review Checklist

Attachment 2 is a checklist provided to facilitate consistent reviews continent-wide for new or functionally modified RAS prior to the RAS installation. The checklist is meant to assist the RC in identifying reliability-related considerations ~~generally~~ relevant to various aspects of RAS design and implementation~~, and also for the purpose of facilitating consistent reviews continent-wide for each RAS to be installed or functionally modified. Most of the checklist items should be applicable to most RAS. There may be checklist items that are not applicable to a given RAS in which case they may be noted as not applicable and skipped in the RC review. Depending on the specifics of the RAS under review, it is possible that other reliability considerations may be identified during the review. Any other reliability considerations, along with their resolution with respect to the particular RAS under review, should be documented along with the Attachment 2 items that were applicable to the specific RAS under review~~.

Technical Justifications for Attachment 3 Content

Database Information

Attachment 3 contains the minimum information that the RC must consolidate into its database for each RAS in its area.

1. RAS name.
   - The name used to identify the RAS.
2. Each RAS-entity and contact information.
   - A reliable phone number or email address should be included to contact ~~the~~each RAS-entity if more information is needed~~. At a minimum, the name of the RAS-entity responsible for the RAS information should be provided~~.
3. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent 60~~-~~ full~~-~~ calendar~~-~~ month (Requirement R4) evaluation date; and, date of retirement, if applicable.
   - Specify each applicable date.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery).
   - A short description of the reason for installing the RAS is sufficient, as long as the main System issues addressed by the RAS can be identified by someone with a reliability need.
5. Description of the ~~contingencies~~Contingencies or System conditions for which the RAS was designed (initiating conditions).
   - A high level summary of the conditions/~~contingencies~~Contingencies is expected. Not all combinations of conditions are required to be listed.
6. Corrective action taken by the RAS.
   - A short description of the actions should be given. For schemes shedding load or generation, the maximum amount of megawatts should be included.
7. Identification of limited impact[9] RAS.
   - Specify whether or not the RAS is designated as limited impact.

~~7.~~8. Any additional explanation relevant to high-level understanding of the RAS.

[9] A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.

- If deemed necessary, any additional information can be included in this section, but is not mandatory.
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Proposed Definition of "Special Protection System"

Special Protection System (SPS)

Background

In Order No. 693, the Commission approved, among other things, the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary"), which included NERC's currently definitions of Special Protection System and Remedial Action Scheme. The NERC Glossary currently defines a Special Protection System as:

> An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

The currently-effective NERC Glossary definition for "Remedial Action Scheme" is a cross-reference to the definition of Special Protection System and reads: "See 'Special Protection System.'" This internal cross-references from Remedial Action Scheme to Special Protection System in lieu of a separate definition was developed to ensure that the terms are used interchangeably even where entities or an interconnection uses one term versus the other.

On February 3, 2015, NERC submitted a petition for approval of a revised definition of "Remedial Action Scheme" to add clarity and to ensure proper identification of Remedial Action Schemes and a more consistent application of related Reliability Standards. As explained in the petition, "[t]he defined terms 'Special Protection System' and 'Remedial Action Scheme' are currently used interchangeably throughout the NERC Regions and in various Reliability Standards, including prior versions of the Proposed Reliability Standards." Along with this proposed revised definition, NERC submitted revisions to various Reliability Standards by replacing the term "Special Protection System" and replacing it with the newly revised "Remedial Action Scheme." As NERC stated, "use of only one term in the NERC Reliability Standards will ensure proper identification of these systems and application of related Reliability Standards." The petition also anticipated future revision to the definition of "Special Protection System" to cross-reference the newly revised and proposed definition of "Remedial Action Scheme." This coordination, which would be achieved by implementing the new definition of "Special Protection System" simultaneously with the Commission approval of the revised definition for "Remedial Action Scheme," will ensure that all references to "Special Protection System" and "Remedial Action Scheme" refer to the same revised definition.

On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking ("NOPR") proposing to accept the revisions to the RAS definition and associated standards, and on November 19, 2015, the Commission issued a Final Order approving the RAS definition and associated standards.

Proposed Definition

Special Protection System (SPS)

See "Remedial Action Scheme"

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan for PRC-012-2

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

Requested Approval

- PRC-012-2 – Remedial Action Schemes

Requested Retirements

- PRC-012-1 – Remedial Action Scheme Review Procedure
- PRC-013-1 – Remedial Action Scheme Database
- PRC-014-1 – Remedial Action Scheme Assessment
- PRC-015-1 – Remedial Action Scheme Data and Documentation
- PRC-016-1 – Remedial Action Scheme Misoperations

Applicable Entities

- Reliability Coordinator
- Planning Coordinator
- RAS-entity – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS

Background

On November 13, 2014, the NERC Board of Trustees approved revisions to the definition for Remedial Action Scheme ("RAS") and associated revisions to related Reliability Standards to consolidate that term with the Glossary term "Special Protection System" (SPS).

In its February 3, 2015 petition to the Commission for approval of the definition of RAS and associated Reliability Standards ("Petition"), NERC noted that, although PRC-012-0, PRC-013-0, and PRC-014-0 were neither approved nor remanded by the Commission in Order No. 693 and were therefore not enforceable, NERC revised these standards to account for the RAS definition revision and changed relevant version numbers to reflect the change. Because of this change, NERC requested retirement of PRC-012-0, PRC-013-0, and PRC-014-0, and provided, for informational purposes only, updated Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1. In the same Petition, NERC requested retirement of PRC-015-0 and PRC-016-0.1 and approval of Reliability Standards PRC-015-1 and PRC-016-1, again implementing changes stemming from the revised definition of RAS.

On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to accept the revisions to the RAS definition and associated standards, and on November 19, 2015, the Commission issued a Final Order approving the RAS definition and associated standards.

General Considerations

Reliability Standard PRC-012-2 was developed to consolidate previously unapproved standards which were designated by the Commission as "fill-in-the-blank" standards and to revise other RAS-related standards. Reliability Standard PRC-012-2 also provides clear and unambiguous responsibilities to the specific users, owners, and operators of the Bulk-Power System. Reliability Standard PRC-012-2 establishes a new working framework between RAS-entities, PCs, and RCs, and this new framework will involve considerable start-up effort. As such, implementation of Reliability Standard PRC-012-2 will occur over a thirty six (36) month period after approval of the standard by applicable governmental authorities.

Effective Date

Where approval by an applicable governmental authority is required, Reliability Standard PRC-012-2 shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. Provisions concerning the initial performance of obligations under Requirements R4, R8, and R9 are outlined below.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction. Provisions concerning the initial performance of obligations under Requirements R4, R8, and R9 are outlined below.

Requirement R4
For existing RAS, initial performance of obligations under Requirement R4 must be completed within sixty (60) full calendar months of the effective date of PRC-012-2, as described above. For new or functionally modified RAS, the initial performance of Requirement R4 must be completed within sixty (60) full calendar months of the date that the RAS is approved by the reviewing RC(s) under Requirement R3.

Requirement R8
For each RAS not designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within six (6) full calendar years of the effective date for PRC-012-2, as described above. For each RAS designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within twelve (12) full calendar years of the effective date for PRC-012-2, as described above.

Requirement R9
For each Reliability Coordinator that does not have a RAS database upon the effective date of PRC-012-2, as described above, the initial obligation under Requirement R9 is to establish a database.

Retirement of Existing Standards

The Reliability Standards for retirement shall be retired immediately prior to the effective date of PRC-012-2 in the particular jurisdiction in which the standard is becoming effective.

Implementation Plan for PRC-012-2

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

Requested Approval

- PRC-012-2 – Remedial Action Schemes

Requested Retirements~~ of Reliability Standards~~~~[1]~~

- PRC-012-~~0 – Special Protection System~~1 – Remedial Action Scheme Review Procedure
- ~~PRC-013-0 – Special Protection System Database~~
- ~~PRC-014-0 – Special Protection System Assessment~~
- ~~PRC-012-1 – Special Protection System Review Procedure~~
- PRC-013-1 – ~~Special Protection System~~Remedial Action Scheme Database
- PRC-014-1 – ~~Special Protection System~~Remedial Action Scheme Assessment
- PRC-015-~~0 – Special Protection System~~1 – Remedial Action Scheme Data and Documentation
- PRC-016-~~0.~~1 – ~~Special Protection System~~Remedial Action Scheme Misoperations
- ~~PRC-015-1 – Special Protection System Data and Documentation~~
- ~~PRC-016-1 – Special Protection System Misoperations~~

~~Prerequisite Approval~~

- ~~Revised definition of "Remedial Action Scheme"~~

Applicable Entities

- Reliability Coordinator
- ~~Transmission Planner~~
- Planning Coordinator
- RAS-~~owner~~entity – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS
- ~~RAS-entity – the RAS-owner designated to represent all RAS-owner(s) for coordinating the review and approval of a RAS~~

~~[1] Retirement includes withdrawal of pending Reliability Standards.~~

~~General Considerations~~

Background

On November 13, 2014, the NERC Board of Trustees approved revisions to the definition for ~~RAS~~Remedial Action Scheme ("RAS") and associated revisions to related Reliability Standards to consolidate that term with the Glossary term "Special Protection System" (SPS).

In its February 3, 2015 petition to the Commission for approval of the definition of RAS and associated Reliability Standards ("Petition"), NERC noted that, although PRC-012-0, PRC-013-0, and PRC-014-0 were neither approved nor remanded by the Commission in Order No. 693 and were therefore not enforceable, NERC revised these standards to account for the RAS definition revision and changed relevant version numbers to reflect the change. Because of this change, NERC requested retirement of PRC-012-0, PRC-013-0, and PRC-014-0, and provided, for informational purposes only, updated Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1. In the same Petition, NERC requested retirement of PRC-015-0 and PRC-016-0.1 and approval of Reliability Standards PRC-015-1 and PRC-016-1~~ and retirement of PRC-015-0 and PRC-016-0.1~~, again implementing changes stemming from the revised definition of RAS.

~~The~~On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to accept the revisions to the RAS definition and associated standards, and on ~~June 18, 2015. As of the date of posting of this Implementation Plan, however~~November 19, 2015, the Commission ~~has not~~ issued ~~an~~a Final Order approving the RAS definition and associated standards.

General Considerations

~~retirement the~~ Reliability ~~Standards enumerated above. Because~~Standard PRC-012-2 was developed to consolidate previously unapproved standards which were designated by the Commission as "fill-in-the-blank" standards and to revise other RAS-related standards. Reliability Standard PRC-012-2 also provides clear and unambiguous responsibilities to the specific users, owners, and operators of the Bulk-Power System. Reliability Standard PRC-012-2 establishes a new working framework between RAS-entities, PCs, and RCs, and this new framework will involve considerable start-up effort. As such, implementation of Reliability Standard PRC-012-2 will occur over a thirty six (36) month period after approval of the standard ~~drafting team for this project has determined that the retirements requested above are necessary to ensure a seamless transition to consolidation of these standards in PRC-012-2, NERC reiterates the requests for retirements already submitted in the Petition and those that are still pending at the Commission~~by applicable governmental authorities.

Effective ~~Dates for PRC-012-2~~Date

~~The proposed~~Where approval by an applicable governmental authority is required, Reliability Standard PRC-012-2 shall become effective on the ~~later of the day after the revised definition of Remedial Acton Scheme becomes effective or the~~ first day of the first calendar quarter that is ~~twelve (12~~thirty six (36) months after the ~~date~~effective date of the applicable governmental authority's order approving the standard~~ is approved by an applicable governmental authority~~, or as otherwise provided for ~~in a jurisdiction where approval~~ by ~~an~~the applicable governmental authority~~ is required for a standard to go into effect. ~~. Provisions concerning the initial performance of obligations under Requirements R4, R8, and R9 are outlined below.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is ~~twelve (12~~thirty six (36) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction. Provisions concerning the initial performance of obligations under Requirements R4, R8, and R9 are outlined below.

Requirement R4

For existing RAS, initial performance of obligations under Requirement R4 must be completed within sixty (60) full calendar months of the effective date of PRC-012-2, as described above. For new or functionally modified RAS, the initial performance of Requirement R4 must be completed within sixty (60) full calendar months of the date that the RAS is approved by the reviewing RC(s) under Requirement R3.

Requirement R8

For each RAS not designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within six (6) full calendar years of the effective date for PRC-012-2, as described above. For each RAS designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within twelve (12) full calendar years of the effective date for PRC-012-2, as described above.

Requirement R9

For each Reliability Coordinator that does not have a RAS database upon the effective date of PRC-012-2, as described above, the initial obligation under Requirement R9 is to establish a database.

Retirement of Existing Standards

The Reliability Standards for retirement shall be retired immediately prior to the ~~Effective Date~~effective date of PRC-012-2 in the particular jurisdiction in which the standard is becoming effective.

Implementation Plan for the Revised Definition of "Special Protection System"

Project 2010-05.3 – Remedial Action Scheme (RAS)

Requested Approval

- Definition of "Special Protection System"

Requested Retirement

- Existing definition of "Special Protection System"

Background

In Order No. 693, the Commission approved, among other things, the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary"), which included NERC's currently definitions of Special Protection System and Remedial Action Scheme. The NERC Glossary currently defines a Special Protection System as:

> An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

The currently-effective NERC Glossary definition for "Remedial Action Scheme" is a cross-reference to the definition of Special Protection System and reads: "See 'Special Protection System.'" This internal cross-references from Remedial Action Scheme to Special Protection System in lieu of a separate definition was developed to ensure that the terms are used interchangeably even where entities or an interconnection uses one term versus the other.

On February 3, 2015, NERC submitted a petition for approval of a revised definition of "Remedial Action Scheme" developed by the standard drafting team Project 2010-05.2 (SPS SDT). As explained in the petition, "[t]he defined terms 'Special Protection System' and 'Remedial Action Scheme' are currently used interchangeably throughout the NERC Regions and in various Reliability Standards, including prior versions of the Proposed Reliability Standards." In developing a solution for this inconsistency, the SPS SDT revised the definition of Remedial Action Scheme to incorporate a higher level of specificity for schemes that are appropriately considered Remedial Action Schemes, to provide more consistent identification of Remedial Action Schemes across the NERC Regions, and to state the relationship between Protection Systems and Remedial Action Schemes. NERC also submitted revisions to various

Reliability Standards by replacing the term “Special Protection System” with the newly revised “Remedial Action Scheme.” As NERC stated, the “use of only one term in the NERC Reliability Standards will ensure proper identification of these systems and application of related Reliability Standards.”

On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking (“NOPR”) proposing to accept the revisions to the RAS definition and associated standards, and on November 19, 2015, the Commission issued a Final Order approving the RAS definition and associated standards.

General Considerations

The petition for revisions to the Definition of “Remedial Action Scheme” and related Reliability Standards also anticipated revision of the definition of “Special Protection System” to cross-reference the newly revised definition of “Remedial Action Scheme.” Coordination of the two terms was completed by the SPS SDT in this phase of the Project (Project 2010-05.3) and will implement the new definition of “Special Protection System” simultaneously with the effective date of the revised definition for “Remedial Action Scheme.” By assigning simultaneous effective dates of the revised definition of “Special Protection System” and “Remedial Action Scheme,” all references to either term in NERC or Regional Entity documents will refer to the same NERC Glossary definition.

Effective Dates

Where approval by an applicable governmental authority is required, the revised definition of Special Protection System shall become effective on the later of the effective date of the applicable governmental authority’s order approving the revised definition of Special Protection System or the effective date of the revised definition of Remedial Action Scheme approved by the Commission on November 19, 2015.

Where approval by an applicable governmental authority is not required, the revised definition of Special Protection System shall become effective on the later of the day that it is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction, or the effective date of the revised definition of Remedial Action Scheme approved by the Commission on November 19, 2015.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)
PRC-012-2 and Proposed Definition of "Special Protection System"

Do not use this form for submitting comments. Use the electronic form to submit comments on draft 2 of **PRC-012-2 – Remedial Action Schemes** and the **Proposed Definition of "Special Protection System"**. The electronic comment form must be submitted by **8 p.m. Eastern, Friday, January 8, 2016.**

Documents and information about this project are available on the project page. If you have questions, contact Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

Background Information

This project is addressing all aspects of Remedial Action Schemes (RAS) and Special Protection Systems (SPS) contained in the RAS/SPS-related Reliability Standards: PRC-012-1, PRC-013-1, PRC-014-1, PRC-015-1, and PRC-016-1. The maintenance of the Protection System components associated with RAS (PRC-017-1 Remedial Action Scheme Maintenance and Testing) are already addressed in PRC-005. PRC-012-2 addresses the testing of the non-Protection System components associated with RAS/SPS and the overall performance of the RAS.

In FERC Order No. 693 (dated March 16, 2007), the Commission identified PRC-012-0, PRC-013-0, and PRC-014-0 as "fill-in-the-blank" standards and did not approve or remand them. These standards are applicable to the Regional Reliability Organizations (RROs), assigning the RROs the responsibility to establish regional procedures and databases, and to assess and document the operation, coordination, and compliance of RAS/SPS. The deference to regional practices precludes the consistent application of RAS/SPS-related Reliability Standard requirements.

The proposed draft of PRC-012-2 corrects the applicability of the fill-in-the-blank standards by assigning the requirement responsibilities to the specific users, owners, and operators of the Bulk-Power System; and incorporates the reliability objectives of all the RAS/SPS-related standards.

On February 3, 2015, NERC submitted a petition for approval of a revised definition of "Remedial Action Scheme" to add clarity and to ensure proper identification of Remedial Action Schemes and a more consistent application of related Reliability Standards. As explained in the petition, "[t]he defined terms 'Special Protection System' and 'Remedial Action Scheme' are currently used interchangeably throughout the NERC Regions and in various Reliability Standards, including prior versions of the Proposed Reliability Standards." Along with this proposed revised definition, NERC submitted revisions to various Reliability Standards by replacing the term "Special Protection System" and replacing it with the newly revised "Remedial Action Scheme." As NERC stated, "use of only one term in the NERC Reliability Standards will ensure proper identification of these systems and application of related Reliability Standards." The petition also anticipated future revision to the definition of "Special Protection System" to cross-reference the newly revised and proposed definition of "Remedial Action Scheme." This coordination, which would be achieved by implementing the new definition of "Special Protection System" simultaneously with the Commission approval of the revised definition for "Remedial Action Scheme," will ensure that all references to "Special Protection System" and "Remedial Action Scheme" refer to the same revised definition. On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking ("NOPR") proposing to accept the revisions to the RAS definition and associated standards, and on November 19, 2015, the Commission issued a Final Order approving the RAS definition and associated standards.

45-day Formal Comment Period

The drafting team made numerous changes to Reliability Standard PRC-012-2 and its implementation plan based on stakeholder comments from the previous posting. The team appreciates the feedback you provided and considered all of your suggestions. The responses to your comments and a summary of the changes are located in the Consideration of Comments document posted on the project page. The drafting team is soliciting stakeholder comments and feedback on the second draft of PRC-012-2 and its implementation plan.

Additionally, the drafting team is soliciting comments and feedback on the revised definition of "Special Protection System" and its implementation plan which are posted for an initial ballot.

Questions

1. **Limited impact designation:** Within the RAS review process of PRC-012-2, the drafting team included a provision that RAS can be designated as “limited impact” if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process. Do you agree with the provision that RAS can be designated as “limited impact”? If no, please provide the basis for your disagreement and an alternate proposal.

   ☐ Yes
   ☐ No
   Comments:

2. **Implementation Plan for PRC-012-2:** The drafting team revised the Implementation Plan to provide clarity and to lengthen the implementation period to thirty-six months to provide the responsible entities adequate time to establish the new working frameworks among functional entities. Do you agree with the revised Implementation Plan? If no, please provide the basis for your disagreement and an alternate proposal.

   ☐ Yes
   ☐ No
   Comments:

3. **Revised Definition of “Special Protection System” and its Implementation Plan:** The drafting team revised the definition of “Special Protection System” to cross-reference the revised definition of “Remedial Action Scheme”. The Implementation Plan for the revised definition of “Special Protection System” aligns with the effective date of the revised definition of “Remedial Action Scheme”. Do you agree with the proposed definition and its implementation plan? If no, please provide the basis for your disagreement and an alternate proposal.

   ☐ Yes
   ☐ No
   Comments:

4. If you have any other comments that you haven’t already provided in response to the above questions, please provide them here.

   Comments:

Mapping Document

Project 2010-5.3 Phase 3 of Protection Systems: Remedial Action Schemes

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include: **R1.1.** Description of the process for submitting a proposed RAS for Regional Reliability Organization review. **R1.2.** Requirements to provide data that describes design, operation, and modeling of a RAS. **R1.3.** 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.	**<u>PRC-012-1 R.1.1</u>**: Covered by Requirements R1, R2 and R3. **<u>PRC-012-1 R.1.2</u>**: Covered by Requirement R1, Attachment 1 **<u>PRC-012-1 R.1.3</u>**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4.1.4 **<u>PRC-012-1 R.1.4</u>**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2, and Requirement R4.1.3.	**R1.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. **R3.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator. **R4.** Each Each Planning Coordinator, at least once every 60 full calendar months, shall:

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1.4. Requirements to demonstrate 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. **R1.5.** Requirements to demonstrate the proposed RAS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures. **R1.6.** Regional Reliability Organization definition of misoperation. **R1.7.** Requirements for analysis and documentation of corrective action plans for all RAS misoperations. **R1.8.** Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure. **R1.9.** Determination, as appropriate, of maintenance and testing requirements.	**PRC-012-1 R.1.5**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4.1.2. **PRC-012-1 R.1.6**: Covered by Requirement R5 **PRC-012-1 R.1.7**: Covered by Requirements R4 and R6 **PRC-012-1 R.1.8**: PRC-012-2 NERC Standards Development Process **PRC-012-1 R.1.9**: Covered by Requirement R8	**4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.3.1** The BES shall remain stable. **4.1.3.2** Cascading shall not occur. **4.1.3.3** Applicable Facility Ratings shall not be exceeded. **4.1.3.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. **4.1.3.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.1.4 Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator. **R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address.

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		5.1.4 The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s). **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator pursuant to Requirements R5, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R8.** Each RAS-entity shall participate in performing a functional test of each of its RAS to verify the overall RAS performance and the proper operation of non-Protection System components: • At least once every six full calendar years for all RAS not designated as limited impact, or

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		• At least once every twelve full calendar years for all RAS designated as limited impact
R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-013-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a RAS installed shall maintain a RAS database. The database shall include the following types of information: **R1.1.** Design Objectives — Contingencies and system conditions for which the RAS was designed, **R1.2.** Operation — The actions taken by the RAS in response to Disturbance conditions, and	**PRC-013-1 R1**: Covered by Requirement R9 **PRC-013-1 R1.1, R1.2, R1.3:** Covered by Requirement R9, Attachment 3	**R9.** Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once every twelve full calendar months.

Reliability Standard: PRC-013-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1.3. Modeling — Information on detection logic or relay settings that control operation of the RAS.		
R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.	**PRC-014-1 R1**: Covered by Requirement R4	**R4.** Each Each Planning Coordinator, at least once every 60 full calendar months, shall: **4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.1.3 Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.3.1** The BES shall remain stable. **4.1.3.2** Cascading shall not occur. **4.1.3.3** Applicable Facility Ratings shall not be exceeded. **4.1.3.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. **4.1.3.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.4** Except for limited impact RAS, 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 is designed.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.2 Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.
R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all RAS installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).	**PRC-014-1 R2**: Covered by Requirement R4	**R4.** Each Each Planning Coordinator, at least once every 60 full calendar months, shall: **4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.3.1** The BES shall remain stable. **4.1.3.2** Cascading shall not occur. **4.1.3.3** Applicable Facility Ratings shall not be exceeded.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.1.3.4 BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. **4.1.3.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.4** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.
R3. The documentation of the Regional Reliability Organization's RAS assessment shall include the following elements:	<u>**PRC-014-1 R3**</u>: Covered by Requirement R4	**R4.** Each Each Planning Coordinator, at least once every 60 full calendar months, shall:

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R3.1. Identification of group conducting the assessment and the date the assessment was performed. **R3.2.** Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed. **R3.3.** Identification of RAS that were found not to comply with NERC standards and Regional Reliability Organization criteria. **R3.4.** Discussion of any coordination problems found between a RAS and other protection and control systems. **R3.5.** Provide corrective action plans for non-compliant RAS.	**PRC-014-1 R3.1 - R3.4:** Covered by Requirement R4 **PRC-014-1 R3.5**: Covered by Requirement R6	**4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.3.1** The BES shall remain stable. **4.1.3.2** Cascading shall not occur. **4.1.3.3** Applicable Facility Ratings shall not be exceeded. **4.1.3.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. **4.1.3.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.1.4 Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator. **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator pursuant to Requirements R5, or • Identifying a deficiency in its RAS pursuant to Requirement R8.

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall maintain a list of and provide data for existing and proposed RAS as specified in Reliability Standard PRC-013-1 R1.	**PRC-015-1 R1**: Covered by Requirement R1, Attachment 1.	**R1.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located.
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-1_R1 prior to being placed in service.	**PRC-015-1 R2**: Covered by Requirements R1, Attachment 1; R2, Attachment 2; and R3.	**R1.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. **R3.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide	Retired P81	N/A

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
documentation of RAS data and the results of Studies that show compliance of new or functionally modified RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).		

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall analyze its RAS operations and maintain a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-1_R1.	**PRC-016-1 R1**: Covered by Requirement R5	**R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall take corrective actions to avoid future misoperations.	**PRC-016-1 R2**: Covered by Requirements R6 and R7.	**R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of:

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		• Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator pursuant to Requirements R5, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R7.** Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: **7.1** Implement the CAP. **7.2** Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).	<u>**PRC-016-1 R3**</u>: Covered by Requirements R5, R6, and R7, Attachment 1.	**R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS.

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		5.1.2 The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s). **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator pursuant to Requirements R5, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R7.** Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: **7.1** Implement the CAP.

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		7.2 Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

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Mapping Document

Project 2010-5.3 Phase 3 of Protection Systems: Remedial Action Schemes

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include: **R1.1.** Description of the process for submitting a proposed RAS for Regional Reliability Organization review. **R1.2.** Requirements to provide data that describes design, operation, and modeling of a RAS. **R1.3.** 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.	**PRC-012-1 R.1.1**: Covered by Requirements R1, R2 and R3. **PRC-012-1 R.1.2**: Covered by Requirement R1, Attachment 1 **PRC-012-1 R.1.3**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4.1.4 **PRC-012-1 R.1.4**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2, and Requirement R4.1.3.	**R1.** Prior to placing a new or functionally modified RAS in -service or retiring an existing RAS, each RAS-entity shall ~~submit~~provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) ~~that coordinates the area(s)~~ where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to ~~the~~each RAS-entity. **R3.** ~~Following the review performed pursuant to Requirement R2, the RAS-entity shall address each identified issue and obtain approval from each reviewing Reliability Coordinator, prior~~Prior to placing a new or functionally modified RAS in--service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator.

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1.4. Requirements to demonstrate 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. **R1.5.** Requirements to demonstrate the proposed RAS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures. **R1.6.** Regional Reliability Organization definition of misoperation. **R1.7.** Requirements for analysis and documentation of corrective action plans for all RAS misoperations. **R1.8.** Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure. **R1.9.** Determination, as appropriate, of maintenance and testing requirements.	**PRC-012-1 R.1.5**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4.1.2. **PRC-012-1 R.1.6**: Covered by Requirement R5 **PRC-012-1 R.1.7**: Covered by Requirements R4 and R6 **PRC-012-1 R.1.8**: PRC-012-2 NERC Standards Development Process **PRC-012-1 R.1.9**: Covered by Requirement R8	**R4.** Each Each Planning Coordinator, at least once every 60 full calendar months, shall: **4.1** Perform~~**R4.** Each Transmission Planner shall perform~~ an evaluation of each RAS within its planning area ~~at least once every 60 full calendar months and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall~~to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** ~~The~~ Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.3.1** The BES shall remain stable. **4.1.3.2** Cascading shall not occur. **4.1.3.3** Applicable Facility Ratings shall not be exceeded. **4.1.3.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		established by the Transmission Planner and the Planning Coordinator. **4.1.3.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.4** ~~A~~Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator. **R5.** Each RAS-~~owner shall~~entity, within 120~~-~~ full calendar days of a RAS operation or a failure of ~~a~~its RAS to operate when expected, ~~analyze the RAS performance and provide the results of the analysis, including any identified deficiencies, to~~or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s~~). The RAS~~), shall:

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		5.1 Participate in analyzing the RAS operational performance ~~analysis shall~~ to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. ~~**R6.** Within six full calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner~~**5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s). **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s~~).~~) within six full calendar months of: ~~**R8.** At least once every six calendar years, each~~• Being notified of a deficiency in its RAS~~-owner~~ pursuant to Requirement R4, or

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		• Notifying the Reliability Coordinator pursuant to Requirements R5, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R8.** Each RAS-entity shall ~~perform~~participate in performing a functional test of each of its RAS to verify the overall RAS performance and the proper operation of non-Protection System components~~.~~: • At least once every six full calendar years for all RAS not designated as limited impact, or • At least once every twelve full calendar years for all RAS designated as limited impact
R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-013-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a RAS installed shall maintain a RAS database. The database shall include the following types of information: **R1.1.** Design Objectives — Contingencies and system conditions for which the RAS was designed, **R1.2.** Operation — The actions taken by the RAS in response to Disturbance conditions, and **R1.3.** Modeling — Information on detection logic or relay settings that control operation of the RAS.	**PRC-013-1 R1**: Covered by Requirement R9 **PRC-013-1 R1.1**~~:~~ ~~Covered by Requirement R9, Attachment 3~~ ~~**PRC-013-1**~~**, R1.2**~~:~~ ~~Covered by Requirement R9, Attachment 3~~ ~~**PRC-013-1**~~**, R1.3:** Covered by Requirement R9, Attachment 3	**R9.** Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once ~~each~~every twelve full calendar ~~year~~months.
R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.	**PRC-014-1 R1**: Covered by Requirement R4	**R4.** Each ~~Transmission Planner~~Each Planning Coordinator, at least once every 60 full calendar months, shall ~~perform~~: 4.1 Perform an evaluation of each RAS within its planning area ~~at least once every 60 full calendar months and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall~~to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** ~~The~~Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.3.1** The BES shall remain stable. **4.1.3.2** Cascading shall not occur. **4.1.3.3** Applicable Facility Ratings shall not be exceeded. **4.1.3.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		established by the Transmission Planner and the Planning Coordinator. **4.1.3.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.4** ~~A~~Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.
R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all RAS installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).	**PRC-014-1 R2**: Covered by Requirement R4	**R4.** Each ~~Transmission Planner~~Each Planning Coordinator, at least once every 60 full calendar months, shall ~~perform~~: **4.1** Perform an evaluation of each RAS within its planning area ~~at least once every 60 full calendar months and provide the RAS-owner(s) and the reviewing Reliability~~

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		~~Coordinator(s) the results including any identified deficiencies. Each evaluation shall~~to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** ~~The~~Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component ~~inadvertent operation~~malfunction satisfies all of the following: **4.1.3.1** The BES shall remain stable. **4.1.3.2** Cascading shall not occur. **4.1.3.3** Applicable Facility Ratings shall not be exceeded. **4.1.3.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. **4.1.3.5** Transient voltage responses shall be within acceptable limits as established by the

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		Transmission Planner and the Planning Coordinator. **4.1.4** ~~A~~Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.
R3. The documentation of the Regional Reliability Organization's RAS assessment shall include the following elements: **R3.1.** Identification of group conducting the assessment and the date the assessment was performed. **R3.2.** Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.	**PRC-014-1 ~~R2~~R3:** Covered by Requirement R4 **PRC-014-1 R3.1~~:~~** ~~Covered by Requirement R4~~ ~~**PRC-014-1 R3.2:**~~ ~~Covered by Requirement R4~~ ~~**PRC-014-1 R3.3:**~~ ~~Covered by Requirement R4~~	**R4.** Each ~~Transmission Planner~~Each Planning Coordinator, at least once every 60 full calendar months, shall ~~perform~~: **4.1** Perform an evaluation of each RAS within its planning area ~~at least once every 60 full calendar months and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall~~to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R3.3. Identification of RAS that were found not to comply with NERC standards and Regional Reliability Organization criteria. **R3.4.** Discussion of any coordination problems found between a RAS and other protection and control systems. **R3.5.** Provide corrective action plans for non-compliant RAS.	~~PRC-014-1~~ - **R3.4**: Covered by Requirement R4 **PRC-014-1 R3.5**: Covered by Requirement R6	**4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** ~~The~~Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component ~~inadvertent operation~~ malfunction satisfies all of the following: **4.1.3.1** The BES shall remain stable. **4.1.3.2** Cascading shall not occur. **4.1.3.3** Applicable Facility Ratings shall not be exceeded. **4.1.3.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. **4.1.3.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.4** ~~A~~Except for limited impact RAS, 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

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		(defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed. ~~**R6.** Within six full calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner~~**4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator. **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s~~).~~) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator pursuant to Requirements R5, or • Identifying a deficiency in its RAS pursuant to Requirement R8.

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall maintain a list of and provide data for existing and proposed RAS as specified in Reliability Standard PRC-013-1 R1.	**PRC-015-1 R1**: Covered by Requirement R1, Attachment 1.	**R1.** Prior to placing a new or functionally modified RAS in -service or retiring an existing RAS, each RAS-entity shall ~~submit~~provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) ~~that coordinates the area(s)~~ where the RAS is located.
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-1_R1 prior to being placed in service.	**PRC-015-1 R2**: Covered by Requirements R1, Attachment 1; R2, Attachment 2; and R3.	**R1.** Prior to placing a new or functionally modified RAS in -service or retiring an existing RAS, each RAS-entity shall ~~submit~~provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) ~~that coordinates the area(s)~~ where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to ~~the~~each RAS-entity. **R3.** ~~Following the review performed pursuant to Requirement R2, the RAS-entity shall address each identified issue and obtain approval from each reviewing Reliability Coordinator, prior~~Prior to placing a new or functionally modified RAS in~~-~~-service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of RAS data and the results of Studies that show compliance of new or functionally modified RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall analyze its RAS operations and maintain a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-1_R1.	**PRC-016-1 R1**: Covered by Requirement R5	**R5.** Each RAS-~~owner shall~~entity, within 120~~-~~ full calendar days of a RAS operation or a failure of ~~a~~its RAS to operate when expected, ~~analyze the RAS performance and provide the results of the analysis, including any identified deficiencies, to~~or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s~~). The~~), shall: **5.1** Participate in analyzing the RAS operational performance ~~analysis shall~~ to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall take corrective actions to avoid future misoperations.	**PRC-016-1 R2**: Covered by Requirements R6 and R7.	~~**R6.** Within six full calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner~~**R6.** Each RAS-entity

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s~~).~~) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator pursuant to Requirements R5, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R7.** ~~For~~Each RAS-entity shall, for each ~~CAP submitted~~of its CAPs developed pursuant to Requirement R6~~, each RAS-owner shall~~: **7.1** Implement the CAP. **7.2** Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change~~.~~ and when the CAP is completed.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability	**PRC-016-1 R3**: Covered by Requirements R5, R6, and R7, Attachment 1.	**R5.** Each RAS-~~owner shall~~entity, within 120~~-~~ full calendar days of a RAS operation or a failure of ~~a~~its RAS to operate when expected, ~~analyze the RAS performance and provide the results of the analysis, including any identified deficiencies, to~~or on a mutually agreed upon

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
Organization and NERC on request (within 90 calendar days).		schedule with its reviewing Reliability Coordinator(s~~).~~ ~~The~~), shall: **5.1** Participate in analyzing the RAS operational performance ~~analysis shall~~ to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. ~~**R6.** Within six full calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner~~**5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s). **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s~~).~~) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		• Notifying the Reliability Coordinator pursuant to Requirements R5, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R7.** ~~For~~Each RAS-entity shall, for each ~~CAP submitted~~of its CAPs developed pursuant to Requirement R6~~, each RAS-owner shall~~: **7.1** Implement the CAP. **7.2** Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change~~.~~ and when the CAP is completed.

Violation Risk Factor and Violation Severity Level Justification Document

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

This document provides the standard drafting team (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-012-2. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for PRC-012-2, Requirement R1	
VRF for Requirement R1 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of an entity to submit Attachment 1 information to the responsible Reliability Coordinator for review prior to placing a new or modified RAS in service or retiring an existing RAS could introduce risks to the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R1 relates to two of these areas, specifically (i) protection systems and their coordination; and (ii) clearer criteria for operationally critical facilities. Requirement R1 mandates that entities comply with a review process for new or modified RAS or retirement of RAS. Among the elements of such reviews is the coordination between RAS and other RAS and between RAS and protection and control systems. Requirement R1 also mandates that the RAS-entity provide the Reliability Coordinator relevant RAS information regarding the design and implementation for each new or functionally modified RAS.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements, so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-012-1, Requirement 1, Parts R1.1 – R1.5 which specifies attributes of the RRO process to review RAS (R1.1), provision of pertinent RAS data (R1.2), dependability (R1.3) and security (R1.4) of design, and coordination with other RAS and protection systems (R1.5), and has a Medium VRF.
FERC VRF G4 Discussion	A medium VRF is appropriate for this requirement because failure of an entity to submit Attachment 1 information to the responsible Reliability Coordinator for review prior to placing a new or modified RAS in

VRF Justifications for PRC-012-2, Requirement R1	
VRF for Requirement R1 is Medium	
Guideline 4- Consistency with NERC Definitions of VRFs	service or retiring an existing RAS could introduce risks to the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The RAS-entity failed to provide the information identified in Attachment 1 to each Reliability Coordinator prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R1.

VSL Justifications for PRC-012-2, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-012-1, Requirements R1.1 – R1.5 which had four established Levels of Non-Compliance. The requirement is binary with only a Severe VSL so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2b: N/A
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R2	
VRF for Requirement R2 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R2 because failure of a Reliability Coordinator to perform the RAS reviews and identify potential risks presented by the RAS could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R2 relates to one of these areas, specifically, protection systems and their coordination. Requirement R2 mandates that Reliability Coordinators review the RAS to determine if a RAS avoids adverse interactions with other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-014-1, Requirement R1, which is related to the review of RAS.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R2 because failure of a Reliability Coordinator to perform the RAS reviews and identify potential risks presented by the RAS could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R2	
VRF for Requirement R2 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90 full calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in accordance with Requirement R2.

VSL Justifications for PRC-012-2, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-014-0, Requirement R1 which also had four established Levels of Non-Compliance. This requirement has VSLs comparable to the established Levels of Non-Compliance in that requirement, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R3	
VRF for Requirement R3 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of a RAS entity to address the reliability issues identified during the RC review before placing it into service could introduce risks to the BES that could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R3 relates to one of these areas, specifically protection systems and their coordination. Requirement R3 requires the RAS-entity to address each identified reliability issue which includes the coordination between RAS and other RAS and between RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-015-0 Requirement R2 which requires the entity to comply with the RRO procedure as defined in PRC-012-1 Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of a RAS entity to address the reliability issues identified during the RC review before placing it into service could introduce risks to the BES that could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R3	
VRF for Requirement R3 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The RAS-entity failed to resolve identified reliability issue(s) to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R3.

VSL Justifications for PRC-012-2, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-015-0, Requirement R2 which has four established VSLs. This requirement is binary with only a Severe VSL so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2b: N/A
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R4	
VRF for Requirement R4 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R4 because failure to perform the periodic evaluation could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R4 relates to one of these areas, specifically protection systems and their coordination. Requirement R4 mandates that entities perform periodic evaluations of each RAS to ensure that changes in System conditions have not changed the effectiveness of the RAS to mitigate the events or System conditions for which it was designed. Requirement R4 incorporates all actions necessary to determine if a RAS avoids adverse interactions with other RAS and protection and control systems
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-2, Requirements R3 which requires the assessment of the effectiveness of UVLS Programs.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R4 because failure to perform the periodic evaluation could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R4	
VRF for Requirement R4 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator performed the evaluation in accordance with Requirement R4, in greater than 60 full calendar months but less than or equal to 61 full calendar months.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, in greater than 61 full calendar months but less than or equal to 62 full-calendar months	The Planning Coordinator performed the evaluation in accordance with Requirement R4, in greater than 62 full calendar months but less than or equal to 63 full calendar months. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate one of the Parts 4.1.1 through 4.1.4.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but in greater than 63 full calendar months. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate two or more of the Parts 4.1.1 through 4.1.4. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to provide the results to one or more of the

VSLs for PRC-012-2, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
			receiving entities listed in Part 4.2. OR The Planning Coordinator failed to perform the evaluation in accordance with Requirement R4.

VSL Justifications for PRC-012-2, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-014-0, Requirement R1 which has four established Levels of Non-Compliance. This requirement has comparable VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R4	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R4	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R5	
VRF for Requirement R5 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R5 because failure to perform the RAS operational performance analysis could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R5 relates to one of these areas, specifically protection systems and their coordination. Requirement R5 mandates that entities perform RAS operational performance analysis to verify that the RAS operation and the resulting System performance was consistent with the Contingency events or System conditions for which it was designed. Requirement R5 incorporates all actions necessary to identify coordination issues between RAS and other RAS and between RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-2, Requirements R4 which requires evaluation of the UVLS Program performance during a voltage excursion event.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R5 because failure to perform the RAS operational performance analysis could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R5	
VRF for Requirement R5 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity performed the analysis in accordance with Requirement R5, but was late by less than or equal to 10 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address one of the Parts 5.1.1 through 5.1.4.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address two or more of the Parts 5.1.1 through 5.1.4. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to provide the results (Part 5.2) to one or more of the reviewing Reliability Coordinator(s).

VSLs for PRC-012-2, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
			OR The RAS-entity failed to perform the analysis in accordance with Requirement R5

VSL Justifications for PRC-012-2, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0.1, Requirement R1, and PRC-012-1, Requirement R1.7, which have four established Levels of Non-Compliance. This requirement has comparable VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R5	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R5	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R6	
VRF for Requirement R6 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because the failure of an entity to develop a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R6 addresses one of these areas, specifically protection systems and their coordination. CAPs establish mitigation plans and timetable to address deficiencies that could cause adverse interactions between RAS and other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-016-0, Requirements R2 and R3 which require a RAS-owner take corrective actions to avoid future misoperations and provide documentation of the corrective action plans to the RRO.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because the failure of an entity to develop a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

VRF Justifications for PRC-012-2, Requirement R6	
VRF for Requirement R6 is Medium	
	preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30 full calendar days. OR The RAS-entity developed a Corrective Action Plan but failed to submit it to one or more of its reviewing Reliability Coordinator(s) in accordance with Requirement R6. OR

VSLs for PRC-012-2, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
			The RAS-entity failed to develop a Corrective Action Plan in accordance with Requirement R6.

VSL Justifications for PRC-012-2, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0, Requirements R2 and R3, and has VSLs comparable to the established Levels of Non-Compliance in those requirements, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R6	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R6	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R7	
VRF for Requirement R7 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of an entity to implement a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R7 relates to one of these areas, specifically protection systems and their coordination. Implemented CAPs address deficiencies that could cause adverse interactions between RAS and other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-016-0, Requirements R2 and R3 which require a RAS-owner take corrective actions to avoid future misoperations and provide documentation of the corrective action plans to the RRO.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of an entity to implement a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

VRF Justifications for PRC-012-2, Requirement R7	
VRF for Requirement R7 is Medium	
	preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity implemented a CAP in accordance with Requirement R7, Part 7.1, but failed to update the CAP (Part 7.2) if actions or timetables changed, or failed to notify (Part 7.3) each of the reviewing Reliability Coordinator(s) of the updated CAP or completion of the CAP.	N/A	N/A	The RAS-entity failed to implement a CAP in accordance with Requirement R7, Part 7.1.

VSL Justifications for PRC-012-2, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0, Requirement R2 and has VSLs comparable to the established Levels of Non-Compliance in that requirement, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Lower and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R8	
VRF for Requirement R8 is High	
NERC VRF Discussion	A High VRF is appropriate for this Requirement since failure to perform functional testing may allow latent failures to persist in a RAS. These latent failures could result in an unintended operation or a failure to operate, either of which could directly contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures. For these reasons, the requirement meets the NERC criteria for a High VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R8 has interactions in three of these areas, specifically (i) protection systems and their coordination, (ii) communication protocol and facilities, and (iii) appropriate use of transmission loading relief. RAS interactions occur with protection systems, utilize communication protocols and facilities for proper functioning, and are often used for transmission loading relief.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements, so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-005-3, Requirement R3 which requires the maintenance of Protection System Components and has a VRF of High.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A High VRF is appropriate for this Requirement since failure to perform functional testing may allow latent failures to persist in a RAS. These latent failures could result in an unintended operation or a failure to operate, either of which could directly contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures. For these reasons, the requirement meets the NERC criteria for a High VRF.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VRF Justifications for PRC-012-2, Requirement R8	
VRF for Requirement R8 is High	
mingle More than One Obligation	

VSLs for PRC-012-2, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by less than or equal to 30 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 90 full calendar days. OR The RAS-entity failed to perform the functional test for a RAS as specified in Requirement R8.

VSL Justifications for PRC-012-2, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-017-0, Requirements R1 and R2, which had VSLs of Lower, Moderate, High, and Severe. This requirement has VSLs comparable to the established VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R8	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R9	
VRF for Requirement R9 is Lower	
NERC VRF Discussion	A Lower VRF is appropriate for this requirement because the failure of an entity to update the RAS database, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R9 does not address any of the identified areas; therefore, the FERC VRF G1 Discussion is not applicable.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with PRC-010-2 Requirement R6 and PRC-006-1 Requirement R6, which have an approved VRF of Lower.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A Lower VRF is appropriate for this requirement because the failure of an entity to update the RAS database, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90 full calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

VSL Justifications for PRC-012-2, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-013-0, Requirement R1 and has VSLs comparable to the established Levels of Non-Compliance of that requirements, so there is no consequence of lowering the current level of compliance.

VSL Justifications for PRC-012-2, Requirement R9	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations**FERC VSL G3** Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is based upon a single violation, not a cumulative number of violations.The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

Violation Risk Factor and Violation Severity Level Justification Document

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

This document provides the standard drafting team (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-012-2. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange

- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for PRC-012-2, Requirement R1	
VRF for Requirement R1 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of an entity to submit Attachment 1 information to the responsible Reliability Coordinator for review prior to placing a new or modified RAS in service or retiring an existing RAS could introduce risks to the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R1 relates to two of these areas, specifically (i) protection systems and their coordination; and (ii) clearer criteria for operationally critical facilities. Requirement R1 mandates that entities comply with a review process for new or modified RAS or retirement of RAS. Among the elements of such reviews is the coordination between RAS and other RAS and between RAS and protection and control systems. Requirement R1 also mandates that the RAS-entity provide the Reliability Coordinator relevant RAS information regarding the design and implementation for each new or functionally modified RAS.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements, so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-012-1, Requirement 1, Parts R1.1 – R1.5 which specifies attributes of the RRO process to review RAS (R1.1), provision of pertinent RAS data (R1.2), dependability (R1.3) and security (R1.4) of design, and coordination with other RAS and protection systems (R1.5), and has a Medium VRF.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of an entity to submit Attachment 1 information to the responsible Reliability Coordinator for review prior to placing a new or modified RAS in service or retiring an existing RAS could introduce risks to the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R1	
VRF for Requirement R1 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The RAS-entity failed to ~~submit~~provide the information identified in Attachment 1 to ~~one or more of the~~each Reliability Coordinator~~(s)~~ prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R1.

VSL Justifications for PRC-012-2, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-012-1, Requirements R1.1 – R1.5 which had four established Levels of Non-Compliance. The requirement is binary with only a Severe VSL so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2b: N/A
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R2	
VRF for Requirement R2 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R2 because failure of a Reliability Coordinator to perform the RAS reviews and identify potential risks presented by the RAS could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R2 relates to one of these areas, specifically, protection systems and their coordination. Requirement R2 mandates that Reliability Coordinators review the RAS to determine if a RAS avoids adverse interactions with other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-014-1, Requirement R1, which is related to the review of RAS.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R2 because failure of a Reliability Coordinator to perform the RAS reviews and identify potential risks presented by the RAS could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R2	
VRF for Requirement R2 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30~~-~~ full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30~~-~~ full calendar days but less than or equal to 60~~-~~ full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 60~~-~~ full calendar days but less than or equal to 90~~-~~ full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90~~-~~ full calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in accordance with Requirement R2.

VSL Justifications for PRC-012-2, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-014-0, Requirement R1 which also had four established Levels of Non-Compliance. This requirement has VSLs comparable to the established Levels of Non-Compliance in that requirement, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R3	
VRF for Requirement R3 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of a RAS entity to address the reliability issues identified during the RC review before placing it into service could introduce risks to the BES that could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R3 relates to one of these areas, specifically protection systems and their coordination. Requirement R3 requires the RAS-entity to address each identified reliability issue which includes the coordination between RAS and other RAS and between RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-015-0 Requirement R2 which requires the entity to comply with the RRO procedure as defined in PRC-012-1 Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of a RAS entity to address the reliability issues identified during the RC review before placing it into service could introduce risks to the BES that could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R3	
VRF for Requirement R3 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The RAS-entity failed to resolve identified reliability issue(s) to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in-~~-~~service or retiring an existing RAS in accordance with Requirement R3.

VSL Justifications for PRC-012-2, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-015-0, Requirement R2 which has four established VSLs. This requirement is binary with only a Severe VSL so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2b: N/A
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R4	
VRF for Requirement R4 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R4 because failure to perform the periodic evaluation could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R4 relates to one of these areas, specifically protection systems and their coordination. Requirement R4 mandates that entities perform periodic evaluations of each RAS to ensure that changes in System conditions have not changed the effectiveness of the RAS to mitigate the events or System conditions for which it was designed. Requirement R4 incorporates all actions necessary to determine if a RAS avoids adverse interactions with other RAS and protection and control systems
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-2, Requirements R3 which requires the assessment of the effectiveness of UVLS Programs.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R4 because failure to perform the periodic evaluation could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R4	
VRF for Requirement R4 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, in greater than 60- full calendar months but less than or equal to 61- full calendar months.	The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, in greater than 61- full calendar months but less than or equal to 62- full--calendar months~~.~~	The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, in greater than 62- full calendar months but less than or equal to 63- full calendar months. OR The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate one of the Parts 4.1.1 through 4.1.4.	The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, but in greater than 63- full calendar months. OR ~~The Transmission Planner failed to perform the evaluation in accordance with Requirement R4.~~ ~~OR~~ ~~The Transmission Planner~~The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate two or more of the Parts 4.1.1 through 4.1.4.

VSLs for PRC-012-2, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
			OR The ~~Transmission Planner~~Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to provide the results to one or more of the ~~RAS-owner(s) and the reviewing Reliability Coordinator(s).~~receiving entities listed in Part 4.2. OR The Planning Coordinator failed to perform the evaluation in accordance with Requirement R4.

VSL Justifications for PRC-012-2, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-014-0, Requirement R1 which has four established Levels of Non-Compliance. This requirement has comparable VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2	Guideline 2a: N/A

VSL Justifications for PRC-012-2, Requirement R4	
Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R4	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R5	
VRF for Requirement R5 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R5 because failure to perform the RAS operational performance analysis could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R5 relates to one of these areas, specifically protection systems and their coordination. Requirement R5 mandates that entities perform RAS operational performance analysis to verify that the RAS operation and the resulting System performance was consistent with the Contingency events or System conditions for which it was designed. Requirement R5 incorporates all actions necessary to identify coordination issues between RAS and other RAS and between RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-2, Requirements R4 which requires evaluation of the UVLS Program performance during a voltage excursion event.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R5 because failure to perform the RAS operational performance analysis could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R5	
VRF for Requirement R5 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The RAS-~~owner~~entity performed the analysis in ~~greater than 120 calendar days, but less than or equal to 130 calendar days in~~ accordance with Requirement R5, but was late by less than or equal to 10 full calendar days.	The RAS-~~owner~~entity performed the analysis in ~~greater~~accordance with Requirement R5, but was late by more than ~~130~~ 10 full calendar days~~,~~ but less than or equal to ~~140~~ 20 full calendar days ~~in accordance with Requirement R5~~.	The RAS-~~owner~~entity performed the analysis in ~~greater~~accordance with Requirement R5, but was late by more than ~~140~~ 20 full calendar days~~,~~ but less than or equal to ~~150~~ 30 full calendar days ~~in accordance with Requirement R5~~. OR The RAS-~~owner~~entity performed the analysis in accordance with Requirement R5, but failed to address one of the Parts 5.1.1 through 5.1.4.	The RAS-~~owner~~entity performed the analysis in ~~greater~~accordance with Requirement R5, but was late by more than ~~150~~ 30 full calendar days. OR ~~The RAS-owner failed to perform the analysis in accordance with Requirement R5.~~ ~~OR~~ ~~The RAS-owner~~The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address two or more of the Parts 5.1.1 through 5.1.4.

VSLs for PRC-012-2, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
			OR The RAS-~~owner~~entity performed the analysis in accordance with Requirement R5, but failed to provide the results (Part 5.2) to one or more of the reviewing Reliability Coordinator(s). OR The RAS-entity failed to perform the analysis in accordance with Requirement R5

VSL Justifications for PRC-012-2, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0.1, Requirement R1, and PRC-012-1, Requirement R1.7, which have four established Levels of Non-Compliance. This requirement has comparable VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R5	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R5	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R6	
VRF for Requirement R6 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because the failure of an entity to develop a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R6 addresses one of these areas, specifically protection systems and their coordination. CAPs establish mitigation plans and timetable to address deficiencies that could cause adverse interactions between RAS and other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-016-0, Requirements R2 and R3 which require a RAS-owner take corrective actions to avoid future misoperations and provide documentation of the corrective action plans to the RRO.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because the failure of an entity to develop a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

VRF Justifications for PRC-012-2, Requirement R6	
VRF for Requirement R6 is Medium	
	preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The RAS-~~owner~~entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10~~-~~ full calendar days.	The RAS-~~owner~~entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10~~-~~ full calendar days but less than or equal to 20~~-~~ full calendar days.	The RAS-~~owner~~entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20~~-~~ full calendar days but less than or equal to 30~~-~~ full calendar days.	The RAS-~~owner~~entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30~~-~~ full calendar days. OR The RAS-~~owner~~entity developed a Corrective Action Plan ~~and~~but failed to submit it to one or more of its reviewing Reliability Coordinator(s) in accordance with Requirement R6. OR

VSLs for PRC-012-2, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
			The RAS-~~owner~~entity failed to develop a Corrective Action Plan in accordance with Requirement R6.

VSL Justifications for PRC-012-2, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0, Requirements R2 and R3, and has VSLs comparable to the established Levels of Non-Compliance in those requirements, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R6	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R6	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R7	
VRF for Requirement R7 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of an entity to implement a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R7 relates to one of these areas, specifically protection systems and their coordination. Implemented CAPs address deficiencies that could cause adverse interactions between RAS and other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-016-0, Requirements R2 and R3 which require a RAS-owner take corrective actions to avoid future misoperations and provide documentation of the corrective action plans to the RRO.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of an entity to implement a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

VRF Justifications for PRC-012-2, Requirement R7	
VRF for Requirement R7 is Medium	
	preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The RAS-~~owner~~entity implemented a CAP ~~(~~in accordance with Requirement R7, Part 7.1~~),~~, but failed to update the CAP (Part 7.2) if actions or timetables changed ~~and~~, or failed to notify ~~one or more~~(Part 7.3) each of the reviewing Reliability Coordinator(s) ~~(Part 7.3), in accordance with Requirement R7~~of the updated CAP or completion of the CAP.	N/A	N/A	The RAS-~~owner~~entity failed to implement a CAP ~~(Part 7.1)~~ in accordance with Requirement R7, Part 7.1.

VSL Justifications for PRC-012-2, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0, Requirement R2 and has VSLs comparable to the established Levels of Non-Compliance in that requirement, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Lower and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R8	
VRF for Requirement R8 is High	
NERC VRF Discussion	A High VRF is appropriate for this Requirement since failure to perform functional testing may allow latent failures to persist in a RAS. These latent failures could result in an unintended operation or a failure to operate, either of which could directly contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures. For these reasons, the requirement meets the NERC criteria for a High VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R8 has interactions in three of these areas, specifically (i) protection systems and their coordination, (ii) communication protocol and facilities, and (iii) appropriate use of transmission loading relief. RAS interactions occur with protection systems, utilize communication protocols and facilities for proper functioning, and are often used for transmission loading relief.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements, so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-005-3, Requirement R3 which requires the maintenance of Protection System Components and has a VRF of High.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A High VRF is appropriate for this Requirement since failure to perform functional testing may allow latent failures to persist in a RAS. These latent failures could result in an unintended operation or a failure to operate, either of which could directly contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures. For these reasons, the requirement meets the NERC criteria for a High VRF.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VRF Justifications for PRC-012-2, Requirement R8	
VRF for Requirement R8 is High	
mingle More than One Obligation	

VSLs for PRC-012-2, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The RAS-~~owner~~entity performed the functional test for a RAS as specified in Requirement R8, but was late by less than or equal to 30~~-~~ full calendar days~~ late~~.	The RAS-~~owner~~entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 30~~-~~ full calendar days but less than or equal to 60~~-~~ full calendar days ~~late~~.	The RAS-~~owner~~entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 60~~-~~ full calendar days but less than or equal to 90~~-~~ full calendar days ~~late~~.	The RAS-~~owner~~entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 90~~-~~ full calendar days~~ late~~. OR The RAS-~~owner~~entity failed to perform the functional test for a RAS as specified in Requirement R8.

VSL Justifications for PRC-012-2, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-017-0, Requirements R1 and R2, which had VSLs of Lower, Moderate, High, and Severe. This requirement has VSLs comparable to the established VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R8	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R9	
VRF for Requirement R9 is Lower	
NERC VRF Discussion	A Lower VRF is appropriate for this requirement because the failure of an entity to update the RAS database, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R9 does not address any of the identified areas; therefore, the FERC VRF G1 Discussion is not applicable.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with PRC-010-2 Requirement R6 and PRC-006-1 Requirement R6, which have an approved VRF of Lower.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A Lower VRF is appropriate for this requirement because the failure of an entity to update the RAS database, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30~~-~~ full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30~~-~~ full calendar days but less than or equal to 60~~-~~ full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60~~-~~ full calendar days but less than or equal to 90~~-~~ full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90~~-~~ full calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

VSL Justifications for PRC-012-2, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-013-0, Requirement R1 and has VSLs comparable to the established Levels of Non-Compliance of that requirements, so there is no consequence of lowering the current level of compliance.

VSL Justifications for PRC-012-2, Requirement R9	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations**FERC VSL G3** Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is based upon a single violation, not a cumulative number of violations.The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

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)

November 2015

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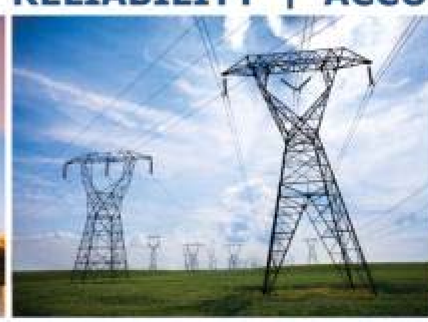


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Question & Answer for PRC-012-2

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 is the Remedial Action Scheme (RAS) review assigned to the Reliability Coordinator?

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 Reliability Coordinators (RCs) and Planning Coordinators (PCs) 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. The Wide Area purview 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, Planning Coordinator, Transmission Planner, or other entities 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 is not expected to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not contain compliance requirements. If Reliability Standards address functions that are not described in the model, the Reliability Standard requirements take precedence over the Functional Model. For further reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009. 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 60 month evaluation of Requirement R4 assigned to the Planning 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, similar to the planning analyses performed by PCs.

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

TOP-1-3 Requirement R13 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-005-4 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.

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

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 the RAS-entities. 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?

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 4.1.4 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.

Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process. Limited impact schemes are not subject to the single component failure aspect of Requirement R4, Part 4.1.4.

6. What is required for RAS "inadvertent operation" and why?

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-012-1 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 4.1.3 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 4.1.3.1 – 4.1.3.5, which are the performance requirements common to all planning events P0–P7.

Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective

date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator in conjunction with the RAS review process. Limited impact schemes are not subject to the single component malfunction aspect of Requirement R4, Part 4.1.3.

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 for continuity with PRC-012-1 R1.3; however, the standard drafting team concluded the classification is unnecessary. The distinction between planning and extreme RAS is captured in Requirement R4, Part 4.1.4 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.

Similarly, the standard drafting team concluded that the SPCS-SAMS distinction between significant and limited RAS was unnecessary for the purpose of maintaining continuity with PRC-012-1, and problematic due to the difficulty of drawing a universally satisfactory delineation in generally worded classification criteria. Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator in conjunction with the RAS review process.

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 a functional modification of a RAS?

A functional modification to a RAS consists of any of the following:

- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement of existing components
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels (addition or removal)

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 device custom logic.
2. Changes to the telecommunication infrastructure or communication facility, such as the replacement of a T1 multiplexor that carries RAS communication when such changes may be important to the 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, or a component that uses the same functionality as the failed component.
2. A firmware upgrade of a RAS component if the change does not require changes in the RAS implementation logic.

The Supplementary Material section of Reliability Standard PRC-012-2 also includes several additional examples of RAS changes that do and do not constitute functional modifications.

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
NERC Staff	Al McMeekin (Standards Developer)	NERC
NERC Staff	Lacey Ourso (Standards Developer)	NERC
NERC Staff	Andrew Wills (Associate Counsel)	NERC

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

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

~~August~~November 2015

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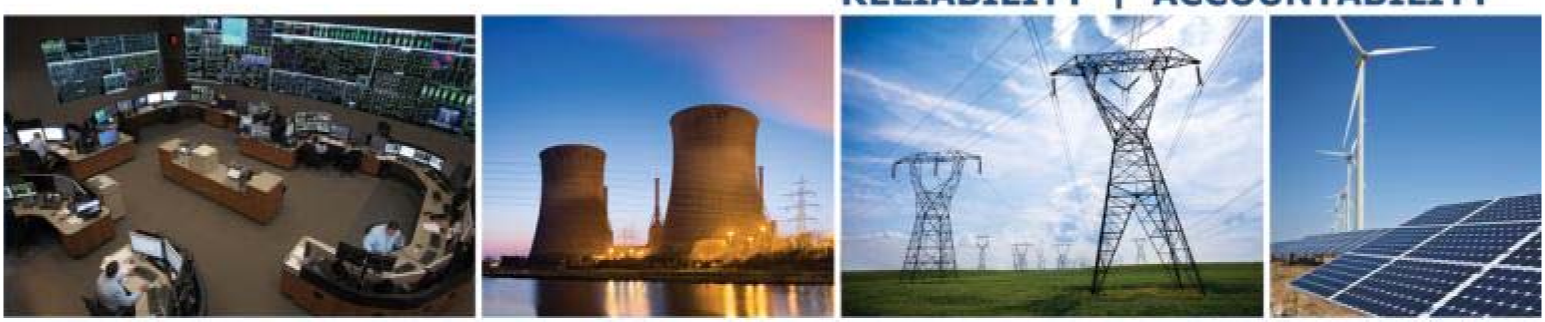

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Question & Answer for PRC-012-2

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~~is the Remedial Action Scheme (RAS) review~~?~~ assigned to the Reliability Coordinator?

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) and Planning Coordinators (PCs) 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~~The Wide Area purview 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~~Planning Coordinator, 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 is not expected to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not contain compliance requirements. If Reliability Standards address functions that are not described in the model, the Reliability Standard requirements take precedence over the Functional Model. For further reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009. 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 60 month evaluation of Requirement R4 assigned to the Planning 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, similar to the planning analyses performed by PCs.

~~2.~~3. Why is the Planning Coordinator not required to perform an annual evaluation of RAS performance?

TOP-~~005-~~1-3 Requirement ~~R3~~R13 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~~4 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?~~ entity?

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 the RAS-~~owners~~entities. 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 4.1.4 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.

Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process. Limited impact schemes are not subject to the single component failure aspect of Requirement R4, Part 4.1.4.

6. What is required for RAS "inadvertent operation" and why?

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~~1 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 4.1.3 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 4.1.3.1 – 4.1.3.5, which are the performance requirements common to all planning events P0–P7.

Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator in conjunction with the RAS review process. Limited impact schemes are not subject to the single component malfunction aspect of Requirement R4, Part 4.1.3.

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~~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 for continuity with PRC-012-1 R1.3; however, the standard drafting team concluded the classification is unnecessary. The distinction between planning and extreme RAS is captured in Requirement R4, Part 4.1.4 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~~Similarly, the standard drafting team concluded that 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. Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator in conjunction with the RAS review process.

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 a 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.~~

A functional modification to a RAS consists of any of the following:

- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement of existing components
- Changes to RAS logic beyond error correcting
- Changes to redundancy levels (addition or removal)

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~~that carries RAS ~~component station. Such~~communication when such changes ~~could affect~~may be important to 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~~.~~, or a component that uses the same functionality as the failed 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.~~

The Supplementary Material section of Reliability Standard PRC-012-2 also includes several additional examples of RAS changes that do and do not constitute functional modifications.

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
NERC Staff	Al McMeekin (Standards Developer)	NERC
NERC Staff	Lacey Ourso (Standards Developer)	NERC
NERC Staff	Andrew Wills (Associate Counsel)	NERC

Standards Announcement Reminder

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)
PRC-012-2 and Proposed Definition of "Special Protection System"

Additional Ballot, Non-binding Poll, and Initial Ballot Open through January 8, 2016

Now Available

An additional ballot for **PRC-012-2 – Remedial Action Schemes**, a non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) and an initial ballot for the **Proposed Definition of "Special Protection System"** are open through **8 p.m. Eastern, Friday, January 8, 2016**.

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Balloting

Members of the ballot pools associated with this project may log in and submit their votes for the standard, associated VRFs and VSLs, and definition by clicking here.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)
PRC-012-2 and Proposed Definition of "Special Protection System"

Formal Comment Period Open through January 8, 2016

Now Available

A 45-day formal comment period for **PRC-012-2 – Remedial Action Schemes** and the **Proposed Definition of "Special Protection System"** is open through **8 p.m. Eastern, Friday, January 8, 2016**.

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Commenting

Use the electronic form to submit comments on the standard and proposed definition. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

An additional ballot for the standard and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels as well as an initial ballot for the proposed definition will be conducted **December 30, 2015 through January 8, 2016**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

Standards Announcement

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)
PRC-012-2 and Proposed Definition of "Special Protection System"

Formal Comment Period Open through January 8, 2016

Now Available

A 45-day formal comment period for **PRC-012-2 – Remedial Action Schemes** and the **Proposed Definition of "Special Protection System"** is open through **8 p.m. Eastern, Friday, January 8, 2016**.

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Standards Announcement

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS) PRC-012-2 and Proposed Definition of "Special Protection System"

Ballot and Non-binding Poll Results

Now Available

A formal comment period and additional ballot for **PRC-012-2 – Remedial Action Schemes**, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels and an initial ballot for the **Proposed Definition of "Special Protection System"** concluded **8 p.m. Eastern, Friday, January 8, 2016.**

The voting statistics are listed below, and the Ballot Results page provides detailed results for the ballots and non-binding poll.

PRC-012-2	Definition of "Special Protection System"	Non-binding Poll
Quorum / Approval	Quorum / Approval	Quorum / Supportive Opinions
83.39% / 60.39%	80.88% / 92.94%	81.21% / 58.39%

Next Steps
The drafting team will consider all comments received during the formal comment and determine the next steps of the project.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/41)
Ballot Name: 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes PRC-012-2 AB 2 ST
Voting Start Date: 12/30/2015 12:01:00 AM
Voting End Date: 1/8/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 266
Total Ballot Pool: 318
Quorum: 83.65
Weighted Segment Value: 60.4

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	87	1	38	0.576	28	0.424	0	14	7
Segment: 2	9	0.7	6	0.6	1	0.1	0	0	2
Segment: 3	72	1	23	0.451	28	0.549	0	6	15
Segment: 4	23	1	5	0.333	10	0.667	0	4	4
Segment: 5	71	1	30	0.638	17	0.362	0	8	16
Segment: 6	44	1	17	0.548	14	0.452	0	6	7
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	2	0.1	1	0.1	0	0	0	1	0
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

Segment: 10	8	0.8	7	0.7	1	0.1	0	0	0
Totals:	318	6.7	128	4.047	99	2.653	0	39	52

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Negative	Third-Party Comments
1	Associated Electric Cooperative, Inc.	Phil Hart		Negative	Comments Submitted
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas		Negative	Third-Party Comments

1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Negative	Comments Submitted
1	Bryan Texas Utilities	John Fontenot		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	Colorado Springs Utilities	Shawna Speer		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Negative	Comments Submitted
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Abstain	N/A
1	Georgia Transmission	Jason Snodgrass	Greg Davis	Negative	Comments

	Corporation				Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Meghan Ferguson	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Negative	Third-Party Comments
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Negative	Third-Party Comments
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
1	National Grid USA	Michael Jones		Negative	Third-Party Comments

1	NB Power Corporation	Alan MacNaughton		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Charles Raney		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Negative	Third-Party Comments
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Rod Kinard	Gul Khan	Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Jared Shakespeare		Negative	Comments Submitted
1	PHI - Potomac Electric Power Co.	David Thorne		Affirmative	N/A
1	Platte River Power Authority	John Collins		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	Comments Submitted
1	Portland General	John Walker		Affirmative	N/A

	Electric Co.				
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Long Duong		Negative	Third-Party Comments
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		Abstain	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Denise Stevens		Negative	Third-Party Comments
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Sunflower Electric Power Corporation	Bertha Ellen Watkins		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A

1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Transmission Agency of Northern California	Eric Olson		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Kim Moulton		None	N/A
1	Western Area Power Administration	Steve Johnson		Abstain	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		None	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	AEP	Michael DeLoach		None	N/A

3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Shuye Teng		Negative	Third-Party Comments
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Negative	Comments Submitted
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A
3	Beaches Energy Services	Steven Lancaster		Negative	Third-Party Comments
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	City of Green Cove Springs	Mark Schultz		Negative	Third-Party Comments
3	City of Leesburg	Chris Adkins		Negative	Third-Party Comments
3	City of Redding	Elizabeth Hadley	Bill Hughes	Negative	Third-Party Comments
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A

3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Abstain	N/A
3	Florida Municipal Power Agency	Joe McKinney		Negative	Comments Submitted
3	Florida Power & Light	Summer Esquerre		None	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	Third-Party Comments
3	Grand River Dam Authority	Jeff Wells		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Third-Party Comments
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Negative	Comments Submitted
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Negative	Third-Party Comments
3	Lakeland Electric	David Hadzima		None	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A

3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Third-Party Comments
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Third-Party Comments
3	NW Electric Power Cooperative, Inc.	John Stickley		Negative	Third-Party Comments
3	Ocala Utility Services	Randy Hahn		None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Blaine Dinwiddie		None	N/A
3	Pacific Gas and Electric Company	John Hagen		None	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Affirmative	N/A
3	Portland General Electric Co.	Thomas Ward		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Negative	Comments Submitted
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Negative	Comments Submitted
3	Public Utility District	Dale Dunckel		Abstain	N/A

	No. 1 of Okanogan County				
3	Puget Sound Energy, Inc.	Andrea Basinski		Affirmative	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Salt River Project	John Coggins		None	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Dana Wheelock		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jeff Neas		Negative	Third-Party Comments
3	Snohomish County PUD No. 1	Mark Oens		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A
3	WEC Energy Group, Inc.	James Keller		Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith	Larry Heckert	Affirmative	N/A

4	Austin Energy	Tina Garvey		Negative	Third-Party Comments
4	Blue Ridge Power Agency	Duane Dahlquist		Abstain	N/A
4	City of Clewiston	Lynne Mila		Negative	Third-Party Comments
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Negative	Third-Party Comments
4	City of Redding	Nick Zettel	Bill Hughes	Negative	Third-Party Comments
4	CMS Energy - Consumers Energy Company	Julie Hegedus		None	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Abstain	N/A
4	Florida Municipal Power Agency	Carol Chinn		Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Negative	Third-Party Comments
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A
4	Keys Energy Services	Stanley Rzad		Negative	Third-Party Comments
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Negative	Third-Party Comments
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		Abstain	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A

4	Seattle City Light	Hao Li		Abstain	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Negative	Comments Submitted
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Comments Submitted
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
5	Austin Energy	Jeanie Doty		Negative	Third-Party Comments
5	Avista - Avista Corporation	Steve Wenke		Negative	Comments Submitted
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Clement Ma		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Abstain	N/A
5	Bonneville Power Administration	Francis Halpin		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Calpine Corporation	Hamid Zakery		None	N/A
5	Choctaw Generation Limited Partnership,	Rob Watson		Affirmative	N/A

	LLLP				
5	City and County of San Francisco	Daniel Mason		Negative	Comments Submitted
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City of Redding	Paul Cummings	Bill Hughes	Negative	Third-Party Comments
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle	Kelly Silver	Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		None	N/A
5	Dynegy Inc.	Dan Roethemeyer		Affirmative	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		None	N/A
5	Exelon	Vince Catania		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Abstain	N/A
5	Florida Municipal Power Agency	David Schumann		Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments

5	Hydro-Qu?bec Production	Roger Dufresne		Abstain	N/A
5	JEA	John Babik		Abstain	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		None	N/A
5	Lower Colorado River Authority	Dixie Wells		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Third-Party Comments
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		None	N/A

5	Oglethorpe Power Corporation	Bernard Johnson		Negative	Third-Party Comments
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		Abstain	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Negative	Third-Party Comments
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		None	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	SCANA - South Carolina Electric and Gas Co.	Henry Delk		None	N/A
5	Seattle City Light	Mike Haynes		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		None	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		None	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A

5	Tennessee Valley Authority	Brandy Spraker	Dennis Chastain	Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Affirmative	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		None	N/A
5	WEC Energy Group, Inc.	Linda Horn		Negative	Comments Submitted
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Edward P Cox		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Andrew Gallo		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Alex Spain		Negative	Comments Submitted
6	City of Redding	Marvin Briggs	Bill Hughes	Negative	Third-Party Comments
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston	Kelly Silver	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Louis Slade		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted

6	Edison International - Southern California Edison Company	Earle Saunders		Affirmative	N/A
6	Exelon	Dave Carlson		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Abstain	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		None	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	Platte River Power Authority	Carol Ballantine		Abstain	N/A
6	Portland General Electric Co.	Shawn Davis		Affirmative	N/A

6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		None	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Negative	Third-Party Comments
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Hathaway		Negative	Comments Submitted
6	Xcel Energy, Inc.	Peter Colussy	Amy Casuscelli	Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability	Peter Heidrich		Affirmative	N/A

	Coordinating Council				
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 318 of 318 entries

BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/41)
Ballot Name: 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes Definition IN 1 DEF
Voting Start Date: 12/30/2015 12:01:00 AM
Voting End Date: 1/8/2016 8:00:00 PM
Ballot Type: DEF
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 258
Total Ballot Pool: 318
Quorum: 81.13
Weighted Segment Value: 92.95

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	87	1	63	0.926	5	0.074	0	10	9
Segment: 2	9	0.6	6	0.6	0	0	0	0	3
Segment: 3	72	1	47	0.922	4	0.078	0	6	15
Segment: 4	23	1	15	0.882	2	0.118	0	2	4
Segment: 5	71	1	41	0.891	5	0.109	0	5	20
Segment: 6	44	1	29	0.906	3	0.094	0	4	8
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

Segment: 10	8	0.8	8	0.8	0	0	0	0	0
Totals:	318	6.7	212	6.228	19	0.472	0	27	60

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Negative	Third-Party Comments
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas		Affirmative	N/A

1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Bryan Texas Utilities	John Fontenot		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	Colorado Springs Utilities	Shawna Speer		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission	Jason Snodgrass	Greg Davis	Negative	Comments

	Corporation				Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Meghan Ferguson	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A

1	NB Power Corporation	Alan MacNaughton		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Charles Raney		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Rod Kinard	Gul Khan	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Jared Shakespeare		None	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Affirmative	N/A
1	Platte River Power Authority	John Collins		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	John Walker		Affirmative	N/A

1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Negative	Third-Party Comments
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Sunflower Electric Power Corporation	Bertha Ellen Watkins		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A

1	Transmission Agency of Northern California	Eric Olson		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Kim Moulton		None	N/A
1	Western Area Power Administration	Steve Johnson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Affirmative	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		None	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	None	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Michael DeLoach		None	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public	Jeri Freimuth		Affirmative	N/A

	Service Co.				
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Shuye Teng		Negative	Third-Party Comments
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A
3	Beaches Energy Services	Steven Lancaster		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Green Cove Springs	Mark Schultz		Affirmative	N/A
3	City of Leesburg	Chris Adkins		Affirmative	N/A
3	City of Redding	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A

3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A
3	Florida Power & Light	Summer Esquerre		None	N/A
3	Georgia System Operations Corporation	Scott McGough		Abstain	N/A
3	Grand River Dam Authority	Jeff Wells		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Third-Party Comments
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Affirmative	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A

3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Blaine Dinwiddie		None	N/A
3	Pacific Gas and Electric Company	John Hagen		None	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Affirmative	N/A
3	Portland General Electric Co.	Thomas Ward		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Negative	Comments Submitted
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		Abstain	N/A
3	Puget Sound Energy, Inc.	Andrea Basinski		Affirmative	N/A
3	Sacramento	Rachel Moore	Joe Tarantino	Affirmative	N/A

	Municipal Utility District				
3	Salt River Project	John Coggins		None	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Dana Wheelock		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A
3	WEC Energy Group, Inc.	James Keller		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith	Larry Heckert	Affirmative	N/A
4	Austin Energy	Tina Garvey		Negative	Third-Party Comments
4	Blue Ridge Power Agency	Duane Dahlquist		Affirmative	N/A

4	City of Clewiston	Lynne Mila		Affirmative	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		None	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Abstain	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A
4	Keys Energy Services	Stanley Rzad		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Negative	Third-Party Comments
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		Affirmative	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Abstain	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A

4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Negative	Third-Party Comments
5	Avista - Avista Corporation	Steve Wenke		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Clement Ma		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Abstain	N/A
5	Bonneville Power Administration	Francis Halpin		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Calpine Corporation	Hamid Zakery		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City and County of San Francisco	Daniel Mason		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A

5	City of Redding	Paul Cummings	Bill Hughes	Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle	Kelly Silver	Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		None	N/A
5	Dynegy Inc.	Dan Roethemeyer		Affirmative	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		None	N/A
5	Exelon	Vince Catania		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		None	N/A

5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		None	N/A
5	Lower Colorado River Authority	Dixie Wells		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		None	N/A
5	Oglethorpe Power Corporation	Teresa Czyz		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A

5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Negative	Third-Party Comments
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		None	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	SCANA - South Carolina Electric and Gas Co.	Henry Delk		None	N/A
5	Seattle City Light	Mike Haynes		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		None	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		None	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tennessee Valley Authority	Brandy Spraker	Dennis Chastain	Affirmative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Affirmative	N/A

5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		None	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Edward P Cox		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	City of Redding	Marvin Briggs	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston	Kelly Silver	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Louis Slade		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Third-Party Comments
6	Edison International - Southern California Edison Company	Earle Saunders		Affirmative	N/A
6	Exelon	Dave Carlson		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal	Richard Montgomery		Affirmative	N/A

	Power Agency				
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		None	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	Platte River Power Authority	Carol Ballantine		Affirmative	N/A
6	Portland General Electric Co.	Shawn Davis		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Affirmative	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A

6	Salt River Project	William Abraham		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		None	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Negative	Third-Party Comments
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		None	N/A
6	Xcel Energy, Inc.	Peter Colussy	Amy Casuscelli	Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A

10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/41)
Ballot Name: 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes PRC-012-2 Non-binding Poll AB 2 NB
Voting Start Date: 12/30/2015 12:01:00 AM
Voting End Date: 1/8/2016 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 242
Total Ballot Pool: 297
Quorum: 81.48
Weighted Segment Value: 58.39

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	79	1	27	0.587	19	0.413	0	26	7
Segment: 2	9	0.5	4	0.4	1	0.1	0	2	2
Segment: 3	69	1	19	0.5	19	0.5	0	15	16
Segment: 4	22	1	4	0.333	8	0.667	0	7	3
Segment: 5	66	1	21	0.7	9	0.3	0	17	19
Segment: 6	40	1	11	0.524	10	0.476	0	12	7
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	2	0.1	1	0.1	0	0	0	1	0
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

Segment: 10	8	0.7	6	0.6	1	0.1	0	1	0
Totals:	297	6.4	94	3.844	67	2.556	0	81	55

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Phil Hart		Negative	Comments Submitted
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A

1	Bonneville Power Administration	Donald Watkins		Negative	Comments Submitted
1	Bryan Texas Utilities	John Fontenot		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Abstain	N/A
1	Colorado Springs Utilities	Shawna Speer		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Abstain	N/A
1	Georgia Transmission Corporation	Jason Snodgrass	Greg Davis	Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
1	Hydro One Networks,	Payam Farahbakhsh	Oshani	Affirmative	N/A

	Inc.		Pathirane		
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Meghan Ferguson	Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Negative	Comments Submitted
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Comments Submitted
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A

1	NiSource - Northern Indiana Public Service Co.	Charles Raney		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Negative	Comments Submitted
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Abstain	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Rod Kinard	Gul Khan	Negative	Comments Submitted
1	Peak Reliability	Jared Shakespeare		Negative	Comments Submitted
1	Platte River Power Authority	John Collins		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	John Walker		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Negative	Comments Submitted
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		Abstain	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Abstain	N/A

1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	Transmission Agency of Northern California	Eric Olson		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Kim Moulton		None	N/A

1	Western Area Power Administration	Steve Johnson		Abstain	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		None	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	AEP	Michael DeLoach		None	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Shuye Teng		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Negative	Comments Submitted
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Beaches Energy Services	Steven Lancaster		Negative	Comments Submitted
3	Bonneville Power	Rebecca Berdahl		Negative	Comments

	Administration				Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Comments Submitted
3	City of Green Cove Springs	Mark Schultz		Negative	Comments Submitted
3	City of Leesburg	Chris Adkins		Negative	Comments Submitted
3	City of Redding	Elizabeth Hadley	Bill Hughes	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Abstain	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Abstain	N/A
3	Florida Municipal Power Agency	Joe McKinney		Negative	Comments Submitted
3	Florida Power & Light	Summer Esquerre		None	N/A
3	Georgia System	Scott McGough		Negative	Comments

	Operations Corporation				Submitted
3	Grand River Dam Authority	Jeff Wells		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Comments Submitted
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Affirmative	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Negative	Comments Submitted
3	Lakeland Electric	David Hadzima		None	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Comments Submitted
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Comments Submitted
3	NW Electric Power	John Stickley		Negative	Comments

	Cooperative, Inc.				Submitted
3	Ocala Utility Services	Randy Hahn		None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Blaine Dinwiddie		None	N/A
3	Pacific Gas and Electric Company	John Hagen		None	N/A
3	Portland General Electric Co.	Thomas Ward		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		Abstain	N/A
3	Puget Sound Energy, Inc.	Andrea Basinski		Affirmative	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Salt River Project	John Coggins		None	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Dana Wheelock		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Mark Oens		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A

3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith	Larry Heckert	Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		Abstain	N/A
4	City of Clewiston	Lynne Mila		Negative	Comments Submitted
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Negative	Comments Submitted
4	City of Redding	Nick Zettel	Bill Hughes	Negative	Comments Submitted
4	DTE Energy - Detroit Edison Company	Daniel Herring		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Abstain	N/A
4	Florida Municipal Power Agency	Carol Chinn		Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted
4	Illinois Municipal Electric Agency	Bob Thomas		Abstain	N/A
4	Keys Energy Services	Stanley Rzad		Negative	Comments Submitted

4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Negative	Comments Submitted
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		Abstain	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Abstain	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Comments Submitted
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Avista - Avista Corporation	Steve Wenke		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Clement Ma		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Boise-Kuna Irrigation	Mike Kukla		Abstain	N/A

	District - Lucky Peak Power Plant Project				
5	Bonneville Power Administration	Francis Halpin		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Calpine Corporation	Hamid Zakery		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City and County of San Francisco	Daniel Mason		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City of Redding	Paul Cummings	Bill Hughes	Negative	Comments Submitted
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle	Kelly Silver	Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		None	N/A
5	Duke Energy	Dale Goodwine		None	N/A
5	Dynegy Inc.	Dan Roethemeyer		Affirmative	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		None	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Abstain	N/A

5	Florida Municipal Power Agency	David Schumann		Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Abstain	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		None	N/A
5	Lower Colorado River Authority	Dixie Wells		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A

5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		None	N/A
5	Oglethorpe Power Corporation	Bernard Johnson		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		None	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	SCANA - South Carolina Electric and Gas Co.	Henry Delk		None	N/A
5	Seattle City Light	Mike Haynes		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		None	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		None	N/A
5	Talen Generation,	Donald Lock		None	N/A

	LLC				
5	Tennessee Valley Authority	Brandy Spraker	Dennis Chastain	Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Abstain	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Affirmative	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		None	N/A
5	Xcel Energy, Inc.	David Lemmons		Abstain	N/A
6	AEP - AEP Marketing	Edward P Cox		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Andrew Gallo		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Abstain	N/A
6	Bonneville Power Administration	Alex Spain		Negative	Comments Submitted
6	City of Redding	Marvin Briggs	Bill Hughes	Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston	Kelly Silver	Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Earle Saunders		Affirmative	N/A

6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Abstain	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		None	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	Platte River Power Authority	Carol Ballantine		Abstain	N/A
6	Portland General Electric Co.	Shawn Davis		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Abstain	N/A
6	Sacramento Municipal	Diane Clark	Joe Tarantino	Affirmative	N/A

	Utility District				
6	Salt River Project	William Abraham		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		None	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A

10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Previous 1 Next

Showing 1 to 297 of 297 entries

Survey Report

Survey Details

Name 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS) | PRC-012-2 and Definition

Description

Start Date 11/25/2015

End Date 1/8/2016

Associated Ballots

2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes Definition IN 1 DEF

2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes PRC-012-2 AB 2 ST

2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes PRC-012-2 Non-binding Poll AB 2 NB

Survey Questions

1. Limited impact designation: Within the RAS review process of PRC-012-2, the drafting team included a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process. Do you agree with the provision that RAS can be designated as "limited impact"? If no, please provide the basis for your disagreement and an alternate proposal.

Yes

No

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2. Implementation Plan for PRC-012-2: The drafting team revised the Implementation Plan to provide clarity and to lengthen the implementation period to thirty-six months to provide the responsible entities adequate time to establish the new working frameworks among functional entities. Do you agree with the revised Implementation Plan? If no, please provide the basis for your disagreement and an alternate proposal.

Yes

No

3. Revised Definition of SPS and its Implementation Plan: The drafting team revised the definition of Special Protection System to cross-reference the revised definition of Remedial Action Scheme. The Implementation Plan for the revised definition of Special Protection System aligns with the effective date of the revised definition of Remedial Action Scheme. Do you agree with the proposed definition and its implementation plan? If no, please provide the basis for your disagreement and an alternate proposal.

Yes

No

4. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

Responses By Question

1. Limited impact designation: Within the RAS review process of PRC-012-2, the drafting team included a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process. Do you agree with the provision that RAS can be designated as "limited impact"? If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Falsey - Invenergy LLC - 3 - FRCC,MRO,WECC,TRE,NPCC,SERC,SPP,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5 - RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

The references to “limited impact” pose significant potential for confusion and impact reliability through ambiguity as currently documented. As written, the term “limited impact” is documented an unofficial definition within a single standard.

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment:

Although we agree there is a concern that the availability of the "limited impact" definition may lead to overuse of this option.

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5
Amy Casucelli	Xcel Energy	MRO	1,3,5,6

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter	Segment
Randi Heise	5
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Amy Casuscelli On Behalf of: Peter Colussy, Xcel Energy, Inc. , 6

Selected Answer: Yes

Answer Comment:

We appreciate the SDT's responsiveness to our comment in the previous posting advocating the provision of "limited impact" RAS.

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Tri-State supports the introduction of the concept of "limited impact".

Document Name:

Likes: 0

Dislikes: 0

Laura Nelson - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter	Segment
John Seelke	1,3,5,6
Entity	**Region(s)**
PSEG	NPCC,RFC

Selected Answer: Yes

Answer Comment:

PSEG supports the concept of a limited impact RAS designation within PRC-012-2 provided that it is defined and made available to all RAS entities.

PSEG wishes to note that the criteria for the limited impact designation proposed in draft# 2 of PRC-012-2 are not consistent with the term as it was defined in the NERC SPCS report *"Special Protection Systems (SPS) and Remedial Action Schemes (RAS): Assessment of Definition, Regional Practices, and Application of Related Standards"* dated April, 2013. Under that report, a SPS/RAS has a limited impact to the BES if failure or inadvertent operation of the scheme *does not result* in any of the following:

• Non-Consequential Load Loss ≥ 300 MW;

• Aggregate resource loss (tripping or runback of generation or HVdc) > the largest Real Power resource within the interconnection;

• Loss of synchronism between two or more portions of the system each including more than one generating plant; or

• Negatively damped oscillations.

If none of the four results are projected to occur, the SPS is classified as having a limited impact on the BES.

While PSEG agrees with the existing NPCC, ERCOT, and WECC limited impact designations, PSEG also believes that one NERC-wide limited impact RAS criteria should be included in PRC-012-2 for new limited impact designations. While PSEG does not advocate any specific limited impact RAS criteria, it does note that the cited SPCS report was approved by the NERC Planning Committee. Any RAS that meets such criteria, whether existing or proposed, should receive limited impact designation.

Finally, second draft of PRC-012-2 does not provide an affirmative mechanism for an existing RAS to be classified as limited impact. In order for such a review take place under R2, a RAS-entity must initiate the review (under R1) when: "…*placing a new or functionally modified RAS in-service or retiring and existing RAS"*. Therefore, under our reading of the current draft of PRC-012-2, existing RASs which are not undergoing functional modification do not have an opportunity to be reviewed for a limited impact designation, and R1 should be modified to allow such RAS entities to seek designation for existing RASs as "limited impact." To facilitate such analysis, PSEG's comments in Q4 request that the RAS entity's Planning Coordinator have obligations under R1 to perform the studies related to a RAS's performance that is required in Attachment 1.

Document Name:

Likes: 5 PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
Long Island Power Authority, 1, Ganley Robert
PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Daniel Mason - City and County of San Francisco - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2

Selected Answer: Yes

Answer Comment:

The Standards Drafting Team (SDT) states a RAS which is "…new or functionally modified RAS implemented after the effective date…" can be recognized as "limited impact." Can a RAS currently in place and not within the Types already "grandfathered" by this standard (e.g., Type 3 in NPCC, Type 2 in ERCOT), become recognized as "limited impact?" We request the SDT provide more clarity on the process for determining "limited impact" on existing RASs.

Document Name:

Likes: 0

Dislikes: 0

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer: Yes

Answer Comment:

Tacoma Power appreciates this provision.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter

Colby Bellville

Segment

1,3,5,6

Entity

Duke Energy

Region(s)

FRCC,SERC,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Information

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter	Segment
Charles Yeung	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	

Selected Answer: Yes

Answer Comment:

The SDT states a RAS which is "…new or functionally modified RAS implemented after the effective date…" can be recognized as "limited impact". Can a RAS currently in place and not within the Types already "grandfathered" by this standard, become recognized as "limited impact"? If so, what is the process?

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter	Segment
Pamela Hunter	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer: No

Answer Comment:

Please see response to Question #4.

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Steve Wenke - Avista - Avista Corporation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Eversource Energy - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Gowder - Chris Gowder On Behalf of: Tom Reedy, Florida Municipal Power Pool, 6

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC

Group Information

Group Name: LG&E and KU Energy, LLC

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E adn KU energy, LLC	SERC	1,3,5,6
justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6
Chjarlie Freibert	LG&E and KU Energy, LLC	SERC	3
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Dan Wilson	LG&E and KU Energy, LLC	SERC	5

Voter Information

Voter	Segment
Brent Ingebrigtson	1,3,5,6
Entity	**Region(s)**
LG&E and KU Energy, LLC	SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Information

Group Name: RSC no Con Edison, Hydro Quebec

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
David Burke	Orange and Rockland Utilities	NPCC	3
Wayne Sipperly	New York Power Authority	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7
Kathleen M. Goodman	ISO-New England	NPCC	2
Helen Lainis	Independent Electricity System Operator	NPCC	2
Michael Jones	National Grid	NPCC	3
Silvia Parada Mitchell	NextEra Energy	NPCC	4
Connie Lowe	Dominion	NPCC	4

Voter Information

Voter	Segment

Ruida Shu	1,2,3,4,5,6,7
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rich Hydzik - Rich Hydzik On Behalf of: Bryan Cox, Avista - Avista Corporation, 5, 3, 1
Scott Kinney, Avista - Avista Corporation, 5, 3, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE does not agree with the provision that a RAS can be designated as "limited impact". Moreover, Texas RE recommends the STD reconsider and treat all RASes equally, that affect the reliability of the Bulk Electric System (BES). Texas RE is concerned the proposed criteria for determining a "limited impact" RAS is vague and ambiguous (e.g. "… BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations) which may lead to the approval of a significant number of "limited impact" RASes on the BES, posing a potential risk to reliability. Specifically, the potential risks are that the reduced reliability-related considerations for the Reliability Coordinator (i.e. Attachment 2) and the limited evaluation performed by the Planning Coordinator (i.e. Requirement 4) pertaining to “limited impact” RASes may lead to potential reliability gaps on the BES.

In the ERCOT region, the “Type 1” and “Type 2” designations were removed from the regional operating guides in February 2014, therefore, there is no longer a regional criteria for “limited” or “wide-area” impact as referred to in R4.1.3. As one of the goals of this project was to eliminate the “fill-in-the-blank” requirements, it seems inappropriate to refer to regional criteria within the standard as it does in footnotes 1, 3, 5, and 6. Texas RE requests the SDT remove that information from the footnotes.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Florida Power & Light appreciates the efforts of the Standard Drafting Team in revising PRC-012-2, however we have concerns on the interpretation of "limited impact" as stated in PRC-012-2 standard. In many cases, RAS's that are classified as "limited impact" may have a larger than expected impact due to system changes. As an example, see page 8 of the NPCC Reliability Reference Directory #7 – Special Protection Systems. NPCC states that "it should be recognized that a Type III SPS may, due to system changes become Type 1 or Type II".

To ensure uniform application, we recommend the footnote in Requirement 4 be modified as follows:

"…RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations for the system conditions considered in the latest TPL-001-4 stability assessment."

Document Name:

Likes: 0

Dislikes: 0

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Independent Electricity System Operator - 2 - NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3
Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer: No

Answer Comment:

While Hydro One supports the newly introduced designation of "limited impact" RAS, we feel that its definition should instead read as shown below, in order to ensure that future in-serviced RAS that will be designated by a regional review process as Type 3 (NPCC), Type 2 (ERCOT), or LAPS (WECC) will continue to be designated as having limited impact. This is because at this early stage, it is unclear whether the regional organizations would be modifying or terminating their RAS review process and/or terminology as this process will newly be conducted by the PC. For example, after the standard is approved, new Type 3 RASs added to the NPCC system would not necessarily be designated as being limited impact. This change in verbiage will also minimize the need for RAS-entities to classify RAS into the three categories below:

1) Limited impact as per NERC;

2) Non-limited impact as per NERC;

3) NPCC Type 3 but non-limited impact as per NERC.

"A RAS that was reviewed previously to the effective date of this standard, or after the effective date of this standard, by a regional process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be

recognized as limited impact for the purposes of Requirement 4, Parts 4.1.3 and 4.1.3."

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment:

Limited impact RAS appears to be exempt from R4.1.3 and R4.1.4. The Rationale box for R4 defines the performance required for a “limited impact” RAS, and then R4.1.3 and R1.4.4 define the performance required for RAS except “limited impact” RAS. BPA believes the performance for all RAS should be the same. Limited impact RAS should not be singled out to be exempt from meeting the performance requirements; it is really a matter of whether or not redundancy is required to be able to meet the required performance.

Although BPA agrees that for a “limited impact” RAS the level of review can be lower, we believe a “limited impact” RAS should still be designed such that failure or inadvertent operation of the RAS does not have an adverse impact on an adjacent TP or PC beyond the criteria the system is planned for.

BPA’s comments also apply to Attachment 2.

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - PRC-012-2 Project

Group Member Name	Entity	Region	Segments
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Ryan Strom	Buckeye Power, Inc.	RFC	4
Matt Caves	Western Farmers Electric Cooperative	SPP	1,5
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc. and Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Kevin Lyons	Central Iowa Power Cooperative	MRO	1
Mike Brytowski	Great River Energy	MRO	1,3,5,6

Voter Information

Voter	Segment
Ben Engelby	6
Entity	**Region(s)**
ACES Power Marketing	

Selected Answer: No

Answer Comment:

(1) The SDT needs to provide more details for “limited impact.” This is a vague term that needs to be clarified, as “cause or contribute to BES Cascading” could be interpreted in multiple ways. Any system that fails to operate as designed could be a contributing cause to an outage. How does an entity prove that a RAS

does not cause cascading? It may be impossible to prove that a RAS has limited impact.

(2)   Why does the SDT give the RC the independent authority without any specific criteria or guidelines to determine if the RAS has a limited impact? There should be an objective set of criteria for the RC to make a decision. We suggest adding detailed parameters or specific examples to show how a RAS may have a limited impact. One suggestion is a local area scheme that does not impact a larger area. The SDT could also leverage SPP, WECC or NPCC parameters for determining limited impact that should lead to the SDT to develop continent-wide criteria for determining limited impact RAS.

(3) Why does the SDT include “limited impact” RAS as being applicable to the standard? If it has a limited impact, then it should not apply at all. This proposal by the SDT is contrary to the past two years of NERC’s RAI and RBR initiatives focusing on HIGH RISK activities. By definition, “limited impact” should not matter for BES reliability. The limited impact designation creates unnecessary compliance burdens without a clear benefit to increased reliability of the grid.

Document Name:

Likes: 0

Dislikes: 0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Group Information

Group Name: AECI

Group Member Name	Entity	Region	Segments
Mark Ramsey	N.W. Electric Power Cooperative, Inc.	SERC	1
John Stickley	N.W. Electric Power Cooperative, Inc.	SERC	3
Kevin White	Northeast Missouri Electric Power Cooperative	SERC	1
Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	SERC	3
Michael B Bax	Central Electric Power Cooperative	SERC	1
Adam M Weber	Central Electric Power Cooperative	SERC	3
Denise Stevens	Sho-Me Power Electric Cooperative	SERC	1
Jeff L Neas	Sho-Me Power Electric Cooperative	SERC	3
Walter Kenyon	KAMO Electric Cooperative	SERC	1
Theodore J Hilmes	KAMO Electric Cooperative	SERC	3
Phillip B Hart	Associated Electric Cooperative Inc.	SERC	1
Todd Bennett	Associated Electric Cooperative Inc.	SERC	3
Matt Pacobit	Associated Electric Cooperative Inc.	SERC	5
Brian Ackermann	Associated Electric Cooperative Inc.	SERC	6

Voter Information

Voter	Segment
Phil Hart	1

Entity	Region(s)
Associated Electric Cooperative, Inc.	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

ERCOT supports the comments submitted by the IRC SRC and provides these additional comments.

ERCOT agrees with the SDT that a “limited impact” designation should be available. However, ERCOT no longer uses the RAS designations “Type 1” or “Type 2,” and references to “ERCOT Type 2” in the footnotes and rationale boxes of this draft standard should be removed. The now defunct ERCOT “Type 2” designation was used to identify limited impact RAS.

Today, there are existing RAS in ERCOT that, although they are no longer designated “Type 2” still qualify as “limited impact.” ERCOT requests clarification as to any particular process that would be required to designate an existing RAS as “limited impact.”

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

There are 4 WECC LAPS that exist which could, given failure to operate, contribute to cascading or voltage instability/collapse. Peak will work with WECC during the implementation phase to update these designations.

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2

Voter Information

Voter	Segment
Jason Smith	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	MRO,SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

2. Implementation Plan for PRC-012-2: The drafting team revised the Implementation Plan to provide clarity and to lengthen the implementation period to thirty-six months to provide the responsible entities adequate time to establish the new working frameworks among functional entities. Do you agree with the revised Implementation Plan? If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Falsey - Invenergy LLC - 3 - FRCC,MRO,WECC,TRE,NPCC,SERC,SPP,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment:

As written, the implementation plan creates confusion by singling out the 3 exceptions. SRP recommends identifying the requirements applicable with the 36 month timeframe. Additionally, as written, there is not established effective date for R9 where a database does not exist.

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5
Amy Casucelli	Xcel Energy	MRO	1,3,5,6

Voter Information

Voter

Emily Rousseau

Segment

1,2,3,4,5,6

Entity

MRO

Region(s)

MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter	Segment
Randi Heise	5
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Amy Casuscelli On Behalf of: Peter Colussy, Xcel Energy, Inc. , 6

Selected Answer: No

Answer Comment:

While Xcel Energy agrees with the clarifications in the Implementation Plan, we do not believe that BES reliability is well served by substantially increasing the revised standard's effective date from 12 to 36 months. Recognizing that 12-18 months is typically the minimum time taken by a NERC Standard to progress from industry approval to receiving FERC approval, a 36 months adder would effectively push the standard's effective date to 4 -5 years after industry approval – which we believe is an inordinately long and unnecessary delay to realize the BES reliability benefits promised by the proposed results-based standard. It is hard to conceive why the responsible entities would need 4-5 years "to establish the new working frameworks among functional entities" given that the only substantial process change in the proposed standard is due to the Reliability Coordinator serving as the RAS review/approval entity – and the associated new working framework is needed to support only R2 (and perhaps R3 to some extent), which constitutes a small proportion of the standard.

Therefore, from our perspective, majority of the requirements are the functional responsibility of a single applicable entity and do not require establishing "new working frameworks among functional entities". Consequently, the previous 12 months implementation period is reasonably adequate – particularly because all existing RAS would retain status quo for several years beyond the standard's effective date due to the: (a) provision of limited impact RAS, and (b) grandfathering of all existing approved RAS until a functional modification occurs. We recommend reducing the implementation period back to 12 months to realize enhanced BES reliability in a more timely manner with the new results-based standard.

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laura Nelson - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter

John Seelke

Segment

1,3,5,6

Entity

PSEG

Region(s)

NPCC,RFC

Selected Answer: Yes

Answer Comment:

PSEG strongly supports the 36-month implementation period as fair and reasonable.

Document Name:

Likes: 5

PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
Long Island Power Authority, 1, Ganley Robert
PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Daniel Mason - City and County of San Francisco - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2

Selected Answer: No

Answer Comment:

The SDT should accommodate the designation of “limited impact” RAS during the implementation period of PRC-012-2. As stated in our comments to Question 1 above, there needs to be a process in place to allow the RC and RAS entity to do this.

Document Name:

Likes: 0

Dislikes: 0

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter

Colby Bellville

Segment

1,3,5,6

Entity

Duke Energy

Region(s)

FRCC,SERC,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Information

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter	Segment
Charles Yeung	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	

Selected Answer: No

Answer Comment:

The SDT should accommodate the designation of “limited impact” RAS during the implementation period of PRC-012-2. As stated above, there needs to be a process in place to allow the RC and RAS entity to do this.

There should be an explicit statement in the implementation plan that the obligation for RC approvals apply only to those new and modified RAS after the effective date of the standard, not to those that had been previously reviewed by the RROs under the existing standard.

Document Name:

Likes:	0
Dislikes:	0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter
Pamela Hunter

Segment
1,3,5,6

Entity
Southern Company - Southern Company Services, Inc.

Region(s)
SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Steve Wenke - Avista - Avista Corporation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Eversource Energy - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Gowder - Chris Gowder On Behalf of: Tom Reedy, Florida Municipal Power Pool, 6

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

FMPA believes 36 months is too long, and would suggest a timeframe between 12 and 36 months.

Document Name:

Likes: 0

Dislikes: 0

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC

Group Information

Group Name: LG&E and KU Energy, LLC

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E adn KU energy, LLC	SERC	1,3,5,6
justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6
Chjarlie Freibert	LG&E and KU Energy, LLC	SERC	3
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Dan Wilson	LG&E and KU Energy, LLC	SERC	5

Voter Information

Voter

Brent Ingebrigtson

Segment

1,3,5,6

Entity

LG&E and KU Energy, LLC

Region(s)

SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Information

Group Name: RSC no Con Edison, Hydro Quebec

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
David Burke	Orange and Rockland Utilities	NPCC	3
Wayne Sipperly	New York Power Authority	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7
Kathleen M. Goodman	ISO-New England	NPCC	2
Helen Lainis	Independent Electricity System Operator	NPCC	2
Michael Jones	National Grid	NPCC	3
Silvia Parada Mitchell	NextEra Energy	NPCC	4
Connie Lowe	Dominion	NPCC	4

Voter Information

Voter **Segment**

Ruida Shu | 1,2,3,4,5,6,7

Entity | **Region(s)**

Northeast Power Coordinating Council | NPCC

Selected Answer: Yes

Answer Comment:

Revise in R8 “Requirement R8 must be completed at least once within six (6) full calendar years of the effective date for PRC -0
be completed at least once within six (6) full calendar years AFTER the effective date for PRC -012-2 “prior to”.
the effective date” whereas “after” is clearly stating there is no requirement to present evidence prior to the effective date. If the SDT agrees then R4 should be modified as well.

Revise R9 to:

For each Reliability Coordinator that does not have a RAS database upon the effective date of PRC -012
Requirement R9 is to establish a database on the effective date of PRC-012-2 as describe above. Each RC will perform the obligation of R9 within twelve full calendar months after the effective date of PRC-012-2 as describe above.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rich Hydzik - Rich Hydzik On Behalf of: Bryan Cox, Avista - Avista Corporation, 5, 3, 1
Scott Kinney, Avista - Avista Corporation, 5, 3, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE recommends reducing the implementation period. This is a series of processes that already exist in some form or fashion and should not require a new construct that would take three years. In Requirement R9, the SDT indicates requirements follow “industry practice” which is a twelve month periodicity. Does the SDT contend that there are RASes in place that an RC or PC does not know about?

Texas RE recommends that the SDT *eliminate the proposed implementation period or at least shorten the proposed three-year implementation period for*

PRC-12-2 to six months. Alternatively, the SDT should link the 60-full-calendar month compliance window in PRC-12-2, R4 and the six- and twelve-year compliance periods in PRC-12-2, R8 to the effective date of PRC-12-2 and not the extended date (if any) set forth in the proposed implementation plan.

The proposed PRC-12-2 establishes a process for reviewing new, functionally modified, or retiring RAS. As the SDT has recognized, failing to implement such a RAS review process could result in a significant gap in reliability. Specifically, the SDT stated in the rationale for Requirement R1 that RAS "action(s) can have a *significant impact on the reliability and integrity of the Bulk Electric System (BES)*." Given the importance of the RAS review scheme for reliability, Texas RE believes that three years is too long to implement the process contemplated in the proposed PRC-12-2.

Texas RE also believes that the nature of the review process itself also counsels in favor of a shorter review period. For example, PRC-12-2, R1 – R3 establishes the basic framework for RAS review. These requirements mandate that RAS-entities provide certain information regarding RAS to their respective Reliability Coordinators (RC), a minimum four-month period for the RC to review this information, and then a subsequent obligation for the RAS-entity to resolve any reliability issues identified by the RC prior to installing, functionally modifying, or retiring a particular RAS. Accordingly, these requirements do not contemplate immediate changes to existing physical assets, significant internal process transformations, or other issues that could potentially justify a three-year implementation period. Rather, they largely focus solely on the exchange and review of documentation, such as one-line drawings, for each RAS that is likely already be in the RAS-entity's possession today. RAS-entities and their associated RCs should therefore be able to begin the RAS review process with only minimal lead time following the adoption of PRC-12-2. Texas RE would further note that although RCs may need additional compliance resources to perform the RAS reviews contemplated under PRC-12-2, the existing language in PRC-12-2, R2 already provides RCs and RAS-entities with the flexibility to extend the review period if necessary based on a "mutually agreed upon schedule."

A similar rationale applies to the misoperation review and correction process in PRC-12-2, R5. As the SDT notes, "[t]he correct operation of a RAS is important for maintaining the reliability and integrity of the BES. *Any incorrect operation of a RAS indicates that the RAS effectiveness and/or coordination has been compromised.*" Texas RE agrees with this statement. In light of this fact, however, Texas RE believes that RAS-entities should begin RAS operational performance assessments following a RAS failure or misoperation immediately upon adoption of PRC-12-2 in order to avoid a significant reliability gap.

If the SDT elects to retain an implementation period of any length, Texas RE recommends that such implementation plan not apply to PRC-12-2, R4 and R8. These requirements already have significant time periods for RAS-entities to complete their compliance obligations embedded within them. For example, RAS-entities have six years under PRC-12-2, R8 to complete initial functional tests of their RAS (and 12 years for limited impact RAS if that definition is retained). Given that PRC-12-2, R4 and R8 already provide extended compliance horizons, Texas RE does not believe that additional time is necessary to implement these requirements. Instead, the 6-full-calendar month period in PRC-12-2, R4 and the six- and twelve-year periods in PRC-12-2, R8 should begin on the effective date of PRC-12-2 itself.

Additionally, the Implementation Plan contains the same "limited impact" language Texas RE has concerns about (see response to question 1).

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Independent Electricity System Operator - 2 - NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3
Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer: Yes

Answer Comment:

Hydro One Networks Inc. would like to point out that Requirement R9 on Page 4/5 of the Implementation Plan does not stipulate a time fame by which an RC that does not have a RAS database is required to populate one by.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - PRC-012-2 Project

Group Member Name	Entity	Region	Segments
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Ryan Strom	Buckeye Power, Inc.	RFC	4
Matt Caves	Western Farmers Electric Cooperative	SPP	1,5
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc. and Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Kevin Lyons	Central Iowa Power Cooperative	MRO	1
Mike Brytowski	Great River Energy	MRO	1,3,5,6

Voter Information

Voter	Segment
Ben Engelby	6
Entity	**Region(s)**
ACES Power Marketing	

Selected Answer: Yes

Answer Comment:

We agree with the SDT that the implementation plan is appropriate.

Document Name:

Likes:	0
Dislikes:	0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Group Information

Group Name: AECI

Group Member Name	Entity	Region	Segments
Mark Ramsey	N.W. Electric Power Cooperative, Inc.	SERC	1
John Stickley	N.W. Electric Power Cooperative, Inc.	SERC	3
Kevin White	Northeast Missouri Electric Power Cooperative	SERC	1
Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	SERC	3
Michael B Bax	Central Electric Power Cooperative	SERC	1
Adam M Weber	Central Electric Power Cooperative	SERC	3
Denise Stevens	Sho-Me Power Electric Cooperative	SERC	1
Jeff L Neas	Sho-Me Power Electric Cooperative	SERC	3
Walter Kenyon	KAMO Electric Cooperative	SERC	1
Theodore J Hilmes	KAMO Electric Cooperative	SERC	3
Phillip B Hart	Associated Electric Cooperative Inc.	SERC	1
Todd Bennett	Associated Electric Cooperative Inc.	SERC	3
Matt Pacobit	Associated Electric Cooperative Inc.	SERC	5
Brian Ackermann	Associated Electric Cooperative Inc.	SERC	6

Voter Information

Voter	Segment
Phil Hart	1

Entity	Region(s)
Associated Electric Cooperative, Inc.	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Answer Comment:

ERCOT supports the comments submitted by the IRC SRC and provides these additional comments.

The SDT should consider whether the standard should be clarified to address the designation of “limited impact” RAS during the implementation period of PRC-012-2.

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: No

Answer Comment:

Peak will see significant additional workload burden with this standard implementation and can plan to be ready within 18 months.

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2

Voter Information

Voter	Segment
Jason Smith	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	MRO,SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

3. Revised Definition of SPS and its Implementation Plan: The drafting team revised the definition of Special Protection System to cross-reference the revised definition of Remedial Action Scheme. The Implementation Plan for the revised definition of Special Protection System aligns with the effective date of the revised definition of Remedial Action Scheme. Do you agree with the proposed definition and its implementation plan? If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Falsey - Invenergy LLC - 3 - FRCC,MRO,WECC,TRE,NPCC,SERC,SPP,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5
Amy Casucelli	Xcel Energy	MRO	1,3,5,6

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

While it’s inferred from the standard, there should be an explicit statement in the implementation plan that existing SPS implemented under the RRO standard do not need to be re-approved by the RC.

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter

Randi Heise

Segment

5

Entity

Dominion - Dominion Resources, Inc.

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Amy Casuscelli On Behalf of: Peter Colussy, Xcel Energy, Inc. , 6

Selected Answer: Yes

Answer Comment:

We will appreciate if the Implementation Plan can also address the target date for retirement/elimination of the term/acronym SPS from the NERC Glossary and Standards. Wasn't eliminating the usage of SPS one of the primary drivers for recommending Remedial Action Scheme (RAS) as the preferred term when the RAS/SPS definition was revised?

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laura Nelson - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter	Segment
John Seelke	1,3,5,6
Entity	**Region(s)**
PSEG	NPCC,RFC

Selected Answer: Yes

Answer Comment:

In the future, NERC’s Reliability Standards Development Plan should have the goal of eliminating “Special Protection System” or “SPS” from standards when those standards are revised.

Document Name:

Likes: 5

PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
Long Island Power Authority, 1, Ganley Robert
PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Daniel Mason - City and County of San Francisco - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter

Colby Bellville

Segment

1,3,5,6

Entity

Duke Energy

Region(s)

FRCC,SERC,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Information

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter	Segment
Charles Yeung	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter	Segment
Pamela Hunter	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Steve Wenke - Avista - Avista Corporation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Eversource Energy - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Gowder - Chris Gowder On Behalf of: Tom Reedy, Florida Municipal Power Pool, 6

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC

Group Information

Group Name: LG&E and KU Energy, LLC

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E adn KU energy, LLC	SERC	1,3,5,6
justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6
Chjarlie Freibert	LG&E and KU Energy, LLC	SERC	3
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Dan Wilson	LG&E and KU Energy, LLC	SERC	5

Voter Information

Voter	Segment
Brent Ingebrigtson	1,3,5,6
Entity	**Region(s)**
LG&E and KU Energy, LLC	SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Information

Group Name: RSC no Con Edison, Hydro Quebec

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
David Burke	Orange and Rockland Utilities	NPCC	3
Wayne Sipperly	New York Power Authority	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7
Kathleen M. Goodman	ISO-New England	NPCC	2
Helen Lainis	Independent Electricity System Operator	NPCC	2
Michael Jones	National Grid	NPCC	3
Silvia Parada Mitchell	NextEra Energy	NPCC	4
Connie Lowe	Dominion	NPCC	4

Voter Information

Voter	Segment

Ruida Shu	1,2,3,4,5,6,7
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

**Rich Hydzik - Rich Hydzik On Behalf of: Bryan Cox, Avista - Avista Corporation, 5, 3, 1
Scott Kinney, Avista - Avista Corporation, 5, 3, 1**

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Independent Electricity System Operator - 2 - NPCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3
Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - PRC-012-2 Project

Group Member Name	Entity	Region	Segments
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Ryan Strom	Buckeye Power, Inc.	RFC	4
Matt Caves	Western Farmers Electric Cooperative	SPP	1,5
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc. and Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Kevin Lyons	Central Iowa Power Cooperative	MRO	1
Mike Brytowski	Great River Energy	MRO	1,3,5,6

Voter Information

Voter	Segment
Ben Engelby	6
Entity	**Region(s)**
ACES Power Marketing	

Selected Answer: No

Answer Comment:

The SDT should eliminate the SPS definition in its entirety. An archived definition could also reference the current definition by stating “see Remedial Action Scheme.” There is no reason to keep SPS as an active glossary term. This will only cause more confusion in the industry.

Document Name:

Likes:	0
Dislikes:	0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Group Information

Group Name: AECI

Group Member Name	Entity	Region	Segments
Mark Ramsey	N.W. Electric Power Cooperative, Inc.	SERC	1
John Stickley	N.W. Electric Power Cooperative, Inc.	SERC	3
Kevin White	Northeast Missouri Electric Power Cooperative	SERC	1
Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	SERC	3
Michael B Bax	Central Electric Power Cooperative	SERC	1
Adam M Weber	Central Electric Power Cooperative	SERC	3
Denise Stevens	Sho-Me Power Electric Cooperative	SERC	1
Jeff L Neas	Sho-Me Power Electric Cooperative	SERC	3
Walter Kenyon	KAMO Electric Cooperative	SERC	1
Theodore J Hilmes	KAMO Electric Cooperative	SERC	3
Phillip B Hart	Associated Electric Cooperative Inc.	SERC	1
Todd Bennett	Associated Electric Cooperative Inc.	SERC	3
Matt Pacobit	Associated Electric Cooperative Inc.	SERC	5
Brian Ackermann	Associated Electric Cooperative Inc.	SERC	6

Voter Information

Voter	Segment
Phil Hart	1

Entity	Region(s)
Associated Electric Cooperative, Inc.	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2

Voter Information

Voter	Segment
Jason Smith	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	MRO,SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

4. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

na

Document Name:

Likes: 0

Dislikes: 0

John Falsey - Invenergy LLC - 3 - FRCC,MRO,WECC,TRE,NPCC,SERC,SPP,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

We maintain our previous position that the draft standard is entirely deficient due to the patchwork nature of responsibility for a RAS, especially when there are multiple Owners of portions of the RAS. The standard appears it would be effective where there is only one RAS entity. However, there is no mechanism for overall coordination and responsibility for the case when there are multiple owners. In this respect, the previous draft was superior in that it recognized there needs to be a single RAS Owner that has overall responsibility for ensuring the requirements of PRC-012-2 are met. There is no entity designated to take the lead in developing the data needed for R1, including the technical studies needed to describe system performance. A weak acknowledgement of the need for collaboration among multiple entities is a statement in the R5 Rationale: "RAS-entities may need to collaborate with their associated Transmission Planner to comprehensively analyze RAS operational performance." There is nothing in the Standard as written that will drive the needed "directed collaboration" to bring beneficial results in the analysis of RAS operations and any corrections needed.

Our recommendation is to restore the RAS-Owner entity (or RAS-Coordinator ?) and to identify this entity as the Transmission Owner and/or Transmission Planner having primary interest and technical capability to execute the technical studies (steady state, dynamic, etc), and designate these to have lead or primary responsibility for the Requirements. The individual RAS-entities with ownership of related equipment would be responsible to participate in the requirements as listed, under the umbrella of the primary entity.

Absent a Standard requiring a single entity to take charge of the development of RAS, analysis of its operations, and development of needed CAP's, it appears unlikely that the Standard will actually produce meaningful results, nor an improvement in reliability. This despite the great amount of effort that will be required to ensure compliance.

Document Name:

Likes: 1 Associated Electric Cooperative, Inc., 1, Hart Phil

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:

Answer Comment:

In regards to R8 Oncor Electric Delivery does not differentiate between functional testing of a protection system and functional testing of a RAS. This is an unnecessary requirement, and any responsible entity will perform functional testing of a RAS when maintaining the protection system components of a RAS. Oncor recommends that an entity whose PRC-005-2 maintenance program covers functional testing of its RASs does not have to comply with PRC-012-2 R8. The non protection system components of a RAS are tested when performing maintenance under PRC-005. Hence adhering to the proposed R8 in PRC-012-2 will only require additional documentation while not positively affecting the reliability of the BES.

In regards to R1 Oncor Electric Delivery believes the RAS information required in attachment 1 contains more than is necessary for a review and cannot always be obtained for every RAS. Also providing all this information is not required prior to placing a protection system under PRC-005 in service so it should also not be required under PRC-012-2.

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

SRP appreciates the opportunity to comment on the proposed revisions to PRC-012 and provides the following additional comments related tot he draft posted.

1) Similar to concerns with “limited impact”, “functionally modified” as written is an unofficial defined term within the standard. SRP recommends defining the term “functionally modified” and including it within the NERC Glossary of Terms.

2) Attachment 1 and 2 as originally presented were checklists. As currently written, they are not. Rather they are itemized lists of information to be included

	or assessment to be made. As written the Attachments 1 & 2 create ambiguity in regards to what is expected from the submitter and reviewer. 3) Under R1, the identification within the rationale that "ideally, when there is more than one RAS- entity for a RAS…" is not captured within the language of the standard. SRP agrees with this intention, however recognizes that once the rationale is removed from the standard, this will be lost. SRP recommends adjusting the language of the standard or including the language within the measure to more clearly indicate the intention of the SDT. 4) Under R3, the RAS entity that receives feedback is required to "resolve each issue to obtain approval". This language as written does not specify a resubmittal of the information required under Attachment 1 and fails to reactivate the timeframe identified for the reviewer under R3. SRP recommends adjusting the language to " resolve each issue and resubmit Attachment 1 information to the reviewing RC to obtain approval…". 5) Under R4, there is an inconsistent use of quotes around "limited impact" again pointing to the previously discussed confusion created by imbedding an unofficially defined term within the standard. 6) R^ has a singular/ plural inconsistency "Pursuant to the Requirements R5, or..". This should be singular. Similar to the issue identified under R1, R8 requires each entity to participate in "performing" the functional test. This would require all partial owners to be involved in the functional test of a RAS. Participation is vague and can result in confusion over what would constitute participation. SRP recommends adjusting the language to read "the RAS entity shall perform a functional test..". This would allow joint owners to coordinate the activities
Document Name:	
Likes:	0
Dislikes:	0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5
Amy Casucelli	Xcel Energy	MRO	1,3,5,6

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer:

Answer Comment:

R4.1.3 and R4.1.4 – These requirements refer to ‘single component malfunction’ and ‘single component failure’ respectively. However, the standard does not contain any identification or clarification of which types of components must be included and which may be excluded in RAS evaluations. This deficiency could be addressed by including text in the Supplemental Material section under Requirement 4 that the drafting team developed for a response in its Consideration of Comments for Draft 1 of PRC-012-2.

- *“An exhaustive list of components is not practical given the variety that could be applied in RAS design and implementation. See Item 4a in the Implementation Section of Attachment 1 in the Supplemental Material section for typical RAS components for which redundancy may be considered. The RAS*
components were applied to put a RAS into service and which were already present in the system before a RAS was installed. The RC will make the final determination regarding which components should be regarded as RAS components during its review”.

R5 – This requirement does not obligate RAS-entities to provide their results of the operational performance analysis of a RAS event to impacted Transmission Planners and Planning Coordinators. However, this action should be proposed in the Supplemental Material section.

R6 – This requirement does not obligate RAS-entities to provide their Corrective Action Plans to impacted Transmission Planners and Planning Coordinators. However, this action should be proposed in the Supplemental Material section.

R8 - The purpose of Version 2 of PRC-005 was to consolidate all maintenance and testing of relays under one Standard. Having RAS testing within PRC-012-2 would be contrary to that end. The NSRF proposes to address this concern as follows:

- Functional testing of RAS (as stated in Requirement 8 of PRC-012-2) is a maintenance and testing activity that would be better included in the PRC-005 standard. The present PRC-005-2 Reliability Standard is the maintenance standard that replaces PRC-005-1, 008, 011 and 017 and was designed to cover the maintenance of SPSs/RASs. However, Reliability Standard PRC-005-2 lacks intervals and activities related to non-protective devices such as programmable logic controllers. The NSRF recommends that a requirement for maintenance and testing of non-protective RAS components be added to a revision of PRC-005-6, rather than be an outlying maintenance requirement located in the PRC-012-2 Standard.

R8. Of the proposed Standard states: *Each RAS -entity performing a functional **test** of each of its RAS to **verify** the overall RAS performance and the proper operation of non -Protection Syst components.* Please provide clarification that the word **test** and **verify** is aligned with the definitions contained in the Supplementary Reference and FAQ, PRC-005-2 Protection System Maintenance dated October 2012.

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

a. The Standard Drafting Team gave examples of “functional modifications” in the Rationale Box for R1. Seminole requests that these examples be moved into the Standard language to make these examples more than mere suggestions by the SDT, which would be the case if this language is left in the Application Guidelines.

b. For Requirement R1, can the SDT confirm that each RAS-entity, even if the entity is only a partial ower of a RAS, must submit a fully completed Attachment 1 submission?

c. For Requirement R3, if the RAS-entity disagrees with "issues" the RC indicates, can the RAS-entity document technical reasons why the RAS-entity's design is satisfactory or does the RAS-entity have to get REC approval?

d. Footnote 1 for Requirement 4 appears to state that the only existing limited impact RAS are located in NPCC, ERCOT, and WECC. The footnote does not appear to allow for existing limited impact RAS in other Regions, specifically the FRCC. Seminole requests that the drafting team modify the language in the Standard and footnote to clarify that existing RAS in the FRCC and other Regions can also have existing limited impact RAS.

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter	Segment
Randi Heise	5
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer:

Answer Comment:

Dominion believes that the term “in-kind” included in Footnote 4, “Changes to RAS hardware beyond in -kind repla vague and suggests that the term be clarified such that the reader knows that the replacement of an electromechanical relay with a microprocessor relay is construed as an “in kind” replacement, as the drafting team noted in their December 15th presentation. The concept of “In-kind” replacement could be taken a step further. For example, a discrete ladder logic circuit that includes contacts, overcurrent and voltage relays could be replaced entirely inside the software logic of a multifunction device. From a black-box viewpoint, the old and new RAS would be identical in function. Dominion also suggests for additional consideration that the replacement of many discrete components with a single multifunction component also be considered an “in kind” replacement so long as for a given set of inputs the “black box” produces the same outputs as the previous RAS would. In the case of a breaker failure event, the Standards Drafting Team “SDT” indicates the need for RAS redundancy even though that would be a double failure event (failure of the RAS and failure of the breaker). Dominion suggests that it is sufficiently redundant to use the existing breaker failure relay (non-redundant) to initiate both RAS schemes. This can be accomplished by each RAS using a different contact off the breaker failure relay that was separately fused.

Dominion suggests the SDT consider using a consistent measure of time, either calendar months or full calendar days, for responding and reporting. For example, Requirement 2 states: Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1, shall, within **four** - f **calendar months** of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS -entity." Whereas Requirement 4 states that: "Each RAS entity, within **120** -**full calendar days** of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall:"

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Amy Casuscelli On Behalf of: Peter Colussy, Xcel Energy, Inc. , 6

Selected Answer:

Answer Comment:

We agree with the footnote definition of “limited impact” RAS and the exceptions stated in parts 4.1.3 and 4.1.6 of R4.
Usage of both RAS-owner and RAS-entity in the previous posting of the draft standard was confusing – so we agree with the SDT’s solution to eliminate one of them. We also agree that retaining the previous definition of RAS-owner as Applicable Entity is more appropriate. However, we do not understand what is the compelling need and/or the benefit of reassigning the RAS-owner definition to the RAS-entity. Absent a rationale by the SDT for preferring RAS-entity, we suggest using RAS-owner since it better aligns with the various owners comprised in the definition.

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer:

Answer Comment:

Regarding the third bullet when describing Functional modifications; what does "in-kind" mean? The description in the Supplemental Material describes it but Tri-State believes the phrase "preserves the original functionality" is more appropriate. This is used in several places (Rationale for R1, Att. 1, and Att. 2, at a minimum).

Regarding the fourth bullet when describing Functional modifications; we suggest changing the language to read "...beyond correcting existing errors". The phrase "error correcting" has other implications and is not described in the Supplemental Material.

Tri-State would like to know what the SDT's intentions were when adding the statement "The RC is not expected to possess more information or ability than anticipated by their functional registration as designated by NERC" to the Rationale for Requirement R2. We don't know why that was necessary.

Document Name:

Likes: 0

Dislikes: 0

Laura Nelson - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter	Segment
John Seelke	1,3,5,6
Entity	**Region(s)**
PSEG	NPCC,RFC

Selected Answer:

Answer Comment:

1. Suppose a RAS is intended to cause a generator to run-back under a defined set of conditions. Further, suppose that the generator and the RAS-entity that sends run-back signals to the generator's DCS are different (non-affiliated) companies. Is the generator's DCS a part of the RAS?

2. R4.2 should be expanded with respect to the entities a Planning Coordinator "provides the results of the RAS evaluation including any identified deficiencies." PSEG believes that the results should also be provided to non-RAS entities (i.e., TOs, GOs, and DPs) whose facilities are impacted by the operation of a RAS.

Attachment 1 and R1 should be modified as follows for the reasons provided:

1. In many cases, a single RAS has multiple RAS entities. Attachment 1 should be modified so that each RAS entity's components in the RAS are clearly identified.

2. The entity responsible for providing the information required in Attachment 1 Section II should be identified. For example, item II.6 and III.4 should be completed by the Planning Coordinator (who has the capability to provide that information) rather than the RAS entity. The comments that PSEG submitted for the initial draft addressed this concern and recommended that the RAS entity's Transmission Planner prepare this section; however, since the standard is applicable to "Planning Coordinator," that entity is more appropriate. In response to PSEG's comments, the SDT stated:

"The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval."

PSEG unequivocally agrees with this comment. Therefore, R1 should be modified to state that "each RAS entity and its Planning Coordinator shall provide the information required of it in Attachment 1 …."

With this change, Attachment 1 should be modified to identify which entity (RAS entity or Planning Coordinator) is required to provide what information.

Other Attachment 1 items:

1. Items II.1 and II.2 are duplicative to I.4.e and I.4.f. Therefore, items I.4.e and I.4.f should be deleted. Also, Items II.1 (contingencies and System conditions) and II.2 (RAS action) should be stated so that each contingency and System condition is linked to an expected RAS action (assuming all RAS equipment operates properly). As a simplification, the two items could be combined in to one item: "Each contingency and System condition that the RAS is intended to remedy and the associated RAS response."
2. Item III.1 should have include be expanded to say "and documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in - service or is being maintained." This is required to ensure that non-RAS equipment that is essential to the successful operation of the RAS is not inadvertently removed from service.

Document Name:

Likes: 5 PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
Long Island Power Authority, 1, Ganley Robert

	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
Dislikes:	0

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer:

Answer Comment:

Under Requirement R4.2 additional clarification regarding the as to the “reviewing Reliability Coordinator”. We suggest changing the wording to the “impacted” Reliability Coordinator from “reviewing” as shown below.

4.2. Provide the results of the RAS evaluation including any identified deficiencies to

each impacted Reliability Coordinator and RAS -entity,

Transmission Planner and Planning Coordinator.

Under R5, each RAS entity must review any RAS operation whether the operation was as designed or a there was an unintended or adverse BES response. Under R6, wording calls for a Corrective Action Plan (CAP) to be developed no matter what. We suggest clarifying wording under R6 as follows to limit development of a CAP to when RAS operation caused an unintended or adverse BES response.

R6. Each RAS tity shall participate in developing a Corrective Action Plan (CAP) when RAS operation caused an unintended or adverse BES response and submit the CAP to its impacted Reliability Coordinator(s) within six full calendar months…

Document Name:

Likes: 0

Dislikes: 0

Daniel Mason - City and County of San Francisco - 5 -

Selected Answer:

Answer Comment:

Hetch Hetchy does not agree with the proposed change in the definition of a RAS entity. HHWP believes that the definition of a RAS entity in the last posted version of PRC-012 should be retained and that the RAS owner designated to represent all RAS -own evaluation of RAS impacts is available to the appropriate reliability entities .The proposed change in the definition of a RAS entitiy unnecessarily expands the scope of entities involved in RAS evaluation and is likely to lead to duplication of efforts, or reliabilty gaps. Having a single point of contact for RAS coordination/management is the efficient and effective approach for ensuring that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System.

Document Name:

Likes: 0

Dislikes: 0

William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2

Selected Answer:

Answer Comment:

The Rationale Box for Req. 1 contains important guidelines for when a review of RAS is needed. These should be captured and retained in a standing Guideline. Also, there should be a need to review a RAS when the settings that initiate the RAS are changed.

In the Applicability section of Attachment 3, the three entities identified for obligations to PRC-012-2 are explained with a concluding caveat that these entities can collaborate to meet the requirements of the standard.

“The standard does not stipulate particular compliance methods. RAS -en have the option of collaborating to fulfill their responsibilities for each applicable requirement. Such collaboration and coordination may promote efficiency in achieving the reliability objectives of the requirements; however, the individual RAS -e

example, the individual RAS -e
single, coordinated Attachment 1 to the reviewing RC pursuant to Requirement R1 to initiate the RAS review material to the process.”

We request how this allowance will be included in the RSAW for this standard?

With regards to Req. 4.2, we suggest that the Planning Coordinator only needs to provide evidence of the evaluation results to the RAS-entity if a deficiency is identified.   This will help reduce the compliance burden of submitting documentation if the evaluation results are acceptable.

R6 should be clarified as proposed:

“Each RAS entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of:”

Also, throughout the standard, references to days and months should be standardized. There are references to 60 calendar months, 6 calendar months, and 120 calendar days. These time periods should be expressed in either all months or all days to maintain consistency throughout the standard.

Document Name:

Likes: 0

Dislikes: 0

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer:

Answer Comment:

There are multiple registered Planning Coordinators in GTC's Planning Area, although we joint plan, we would like to propose a simple solution to ensuring that each Planning Coordinator will become aware of any new or materially modified RAS within GTC's Planning Area. Additionally the following rationale is provided to make the basis for our recommendation:

· Not every PC is registered as an RC.

· There may be multiple PCs in 1 RC area

· PCs that do not own transmission assets may not be aware of new or functionally modified RAS's proposed by others and shared only with the RC

· A revision to R1 to include the Planning Coordinator as well is not an option, because some RAS entity's may not be aware of multiple PC registrations in their area.

Therefore, GTC proposes the following new requirement to compliment the obligations of the Planning Coordinator under requirement R4.

R10(proposed new requirement): Each Reliability Coordinator shall provide each Planning Coordinator in their Reliability Coordinator area a copy of the RAS database maintained in accordance with R9, at least once every twelve full calendar months.

Additionally, GTC recommends a slight change to requirement R4 to compliment the new proposed R10 requirement

R4. Each Planning Coordinator that receives a list of RAS's pursuant to R10, at least once every 60 full calendar months, shall:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer:

Answer Comment:

- To promote clarity and efficiency, AZPS suggests adding the following to the Rational for Requirement R4 "*"Ideally, for a RAS which is activated in multiple Planning Coordinator areas, a mutually agreed upon Planning Coordinator of one of the multiple Planning Coordinator areas shall perform the R4 evaluation."*
- Page 6, foot note 1 defines the limited impact RAS as that which cannot "cause or contribute" to cascading etc. The word "contribute" should be removed because it reduces clarity to the standard. The term "contribute" is too broad and creates challenges to precisely evaluate.

- Attachment 2 I. 6 states that a limited impact RAS is determined by the RC. AZPS suggests modifying the language to "…limited impact RAS as determined by the RC or through a regional review process." This will add flexibility to the implementation of the standard and/or allow for an appeal process to be created, if needed.

Document Name:

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer:

Answer Comment:

On page 53 of the redlined version of the proposed standard, in the Technical Justifications for Attachment 1 Content Supporting Documentation for RAS Review section, II. 6., there does not appear to be mention of the limited impact exclusion.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter	Segment
Colby Bellville	1,3,5,6

Entity	Region(s)
Duke Energy	FRCC,SERC,RFC

Selected Answer:

Answer Comment:

General Comment: Duke Energy suggests that the drafting team consider placing the definition of “Remedial Action Scheme” in the standard for the industry to reference while reviewing the proposal. The RAS definition is more complex than most other definitions found in the NERC Glossary and compliance is directly dependent on the proper application of the RAS definition to a particular circumstance. Therefore, any future changes to the definition should be held to the same review and approval process requirements as the RAS standard itself. This would best be accomplished by incorporating the definition as an integral part of the standard. Precedence for this approach already exists in other NERC standards. Without this approach, it is possible to effectively change the scope of the NERC standard without due process.

After further discussion, we have concerns regarding the RC being accountable for the Remedial Action Scheme (RAS) review from a compliance perspective. The RC is not able to or is not in the position to facilitate a review for technical correctness of an RAS, and will be dependent upon a Planning Coordinator/RAS-entity to provide this information. On page 2 of the Question and Answer document supplied by the drafting team on the project, it is stated;

"The RC is not expected to possess more information or ability than anticipated by their functional registration as designated by NERC."

We agree with this sentiment that an entity should not be held accountable for a product that it is not able to or can readily provide. However, further down in the same paragraph, the Q & A document reads;

"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."

The drafting team admits that the RC will need assistance from other entities to perform or provide input for the RAS review. However, the RC will be held accountable for the accuracy and technical input that goes into said review. Requiring an entity to be accountable for information that it may not be able to verify itself is problematic, and should be revisited. We recommend that the drafting team consider adding language in the standard stating that the RC will not be held responsible for the accuracy or content of the technical analysis that is done by the Planning Coordinator/RAS-entity. Rather, the RC is responsible for ensuring that an adequate review is conducted, whether it is an individual review or coordinated review, merely for "identifying reliability-related considerations relevant to various aspects of RAS design and implementation", as stated in the Technical Justification for Attachment 2 Content. This is a task that the RC would be able to evaluate and verify itself without relying on the work of another entity to achieve its compliance.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

ATC has several recommendations for improvement or clarification on the draft Standard, for consideration by the SDT as listed below:

· R4.1.3 and R4.1.4 – These requirements refer to ‘single component malfunction’ and ‘single component failure’ respectively. However, the standard does not contain any identification or clarification of which types of components must be included and which may be excluded in RAS evaluations. This deficiency could be addressed by including text in the Supplemental Material section under Requirement 4 that the drafting team developed for a response in its Consideration of Comments for Draft 1 of PRC-012-2.

“An exhaustive list of components is not practical given the variety that could be applied in RAS design and implementation. See Item 4a in the Implementation Section of Attachment 1 in the Supplemental Material section for typical RAS components for which redundancy may be considered. The RAS *-e* *have a clear understanding of what components were applied to put a RAS into service and which were already present in the system before a RAS was installed. The RC will make the final determination regarding which components should be regarded as RAS components during its review”*.

· R5 – This requirement does not obligate RAS-entities to provide their results of the operational performance analysis of a RAS event to impacted Transmission Planners and Planning Coordinators. However, this action should be proposed in the Supplemental Material section.

· R6 – This requirement does not obligate RAS-entities to provide their Corrective Action Plans to impacted Transmission Planners and Planning Coordinators. However, this action should be proposed in the Supplemental Material section.

· R8 - The purpose of Version 6 of PRC-005 was to consolidate all maintenance and testing of relays under one Standard. Having RAS testing within PRC-012-2 would be contrary to that end. ATC proposes to address this concern as follows:

Functional testing of RAS (as stated in Requirement 8 of PRC-012-2) is a maintenance and testing activity that would be better included in the PRC-005 standard. The present PRC-005-6 Reliability Standard is the maintenance standard that replaces PRC-005-1, 008, 011 and 017 and was designed to cover the maintenance of SPSs/RASs. However, the current Reliability Standard PRC-005-6 lacks intervals and activities related to non-protective devices such as programmable logic controllers. ATC recommends that a requirement for maintenance and testing of non-protective RAS components be added to a revision of PRC-005-6, rather than be an outlying maintenance requirement located in the PRC-012-2 Standard.

If the requirement is not removed and placed in PRC-005 standard, then we suggest that wording be added to R8 to refer the entity to meet the maintenance and testing interval obligations in the latest version of the PRC-005 standard.

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Information

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter	Segment
Charles Yeung	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	

Selected Answer:

Answer Comment:

The rationale Box for R1 contains important guidelines for when a review of RAS is needed. These should be captured and retained in a standing Guideline. Also, there should be a need to review a RAS when the settings that initiate the RAS are changed – which may or may not be covered by the list of circumstances presented.

In the Applicability section of Attachment 3, the three entities identified for obligations to PRC-012-2 are explained with a concluding caveat that these entities can collaborate to meet the requirements of the standard.

“The standard does not stipulate particular compliance methods. RAS tities have the option of collaborating to fulfill their responsibilities for each applicable requirement. Such collaboration and coordination may promote efficiency in

achieving the reliability objectives of the requirements; however, the individual RAS ntity must be able to demonstrate its participation for compliance. As an example, the individual RAS -e
single, coordinated Attachment 1 to the reviewing RC pursuant to Requirement R1 to initiate the RAS review material to the process."

We ask how will this allowance be included in the RSAW for this standard?

R6 should be clarified as proposed:

"Each RAS -
and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of:"

Also, throughout the standard, references to days and months should be standardized. There are references to 60 calendar months, 6 calendar months, and 120 calendar days. These time periods should be expressed in either all months or all days to maintain consistency throughout the standard.

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter	Segment
Pamela Hunter	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer:

Answer Comment:

The owner of **any** protection scheme should be responsible for the correct design and implementation of the scheme – RAS or not. Just like the design of switching to create a blackstart cranking path by a TOP in EOP-005-2, Requirement 6 must be verified by that TOP, the owner of the RAS should be held to the same expectation that the RAS is correctly designed and implemented. If the SDT still believes that some sort of review is required, then that review should be limited in scope to reviewing the generic content of the RAS design and not delve into the technical depth identified in some parts of Attachment 2.

Using the criteria outline by the SDT in its recent webinar, in addition to the independence of the reviewer and geographic span, the team also mentioned “expertise in planning, protection, operations, equipment”. The attributes of this expertise to the level expected do not currently exist in most RC organizations. RC’s are primarily operating entities (and even then primarily in real-time) and not experts in planning (beyond the operating time frame), protection or equipment. Transmission Owners, Transmission Operators and Transmission Planners normally have that expertise. The FERC acknowledged the limited RC technical expertise in evaluating details of restoration plans in its Order 749, Paragraph 38 ("…basis on which a reliability coordinator rejects a restoration plan will necessarily be based on generic engineering criteria…"). The review of a RAS by an RC should not be held to a higher expectation due to similar limited expertise with the equipment and systems involved in a RAS.

The "flexibility" for the RC granted in the requirement to designate a third party would seem to immediately invalidate the original assumptions that the RC has the compelling capability to adequately perform the review while meeting the SDT's characteristics of the reviewing entity. To allow this, while still requiring the RC to be responsible for the review, seems like an improper administrative burden and a potential compliance risk that the RC may assume because it had to find an entity more qualified than itself to perform the review. If an RC is not qualified to review all of the items in Attachment 2 then how can it be held responsible for the results of the review?

Regarding the designation of a third party reviewer, clarification needs to be made regarding what it means to "retain the responsibility for compliance." Does this simply mean that the review takes place or that there is some implied resulting responsibility for the correct design and implementation that the RC is now accountable for?

Finally, also regarding the designation of a third party reviewer, is the term "third party" meant to be any entity not involved in the planning or implementation of the RAS?

The alternative to using the RC? Although there appears to be a movement to remove the RRO as a responsible entity from all standards, those organizations through their membership expertise and committee structures more closely match the characteristics stated by the SDT – expertise in planning/protection/operations/equipment, independence by virtue of the diversity of its members, wide area perspective, and continuity. If for some reason the SDT, believes that the RRO still should not be involved then an alternative could be the Planning Coordinator function which should have similar expertise to the Transmission Planners that are to specify/design a RAS per the functional model yet would have some independence which the SDT is looking for.

Document Name:

Likes:	0
Dislikes:	0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer:

Answer Comment:

Requirement 4 of the standard requires the PC to assess the scheme once every 60 fully calendar months but the standard doesn't requires the RAS entity or RC to provide the PC with the information required to complete this assessment. Suggest adding an additional requirement for the RAS entity to provide data required to assessment the RAS within 30 days of receiving approval from the RC or within 30 calendar days of receiving a written request from the PC.   The PC should also be receiving the information provided to the RC in R5.2, R6, R7.3.

In Attachment 1 the following information appears to be request twice under the General and Description and Transmission Planning Information. If the drafting team is intending different information be provided under the Description and Transmission Planning Information, please consider revising the statement to indicate what is expected.

- General item 4e and Description and Transmission Planning Information item 1
- General item 4f and Description and Transmission Planning Information item 2
- General item 4g and Description and Transmission Planning Information item 5

Document Name:

Likes: 0

Dislikes: 0

Steve Wenke - Avista - Avista Corporation - 5 -

Selected Answer:

Answer Comment:

Moving the review of the RAS schemes up to the Reliabilty Coordinator level does not seem to be the best solution. This responsibility should fall to the Regional Entity.

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:

Answer Comment:

Why the drafting team has not applied the same approach for RAS components ? Why non-protection system components associated to RAS cannot be subject to PRC-005 to avoid functional tests like protection systems components ?

For consistency, all analysis and mitigation of BES protection systems and RAS should be subject to the same standard. Hydro-Quebec TransEnergie suggests removing R5 of PRC-012 and adding into PRC-004.

For consistency, all maintenance and testing requirements of BES protection and control components, including RAS components, should be subject to the same criteria. For instance, the requirement R8 of PRC-012 does not distinguish monitored versus unmonitored devices.

Hydro-Quebec TransEnergie suggest removing R8 of PRC-012 and adding a table of ‘components used for RAS’ in PRC-005.

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Eversource Energy - 3 -

Selected Answer:

Answer Comment:

Comments: Section 4.1.3 reads “Except for “limited impact”1 RAS, the possible inadvertent operation of

the RAS, resulting from any single RAS component malfunction satisfies

all of the following:” Criteria 4.1.3.1 – 4.1.3.5 follow. Should this requirement also pertain to a failure to operate, which is the more severe consequence of have a single RAS component malfunction? Suggest the following wording change: “Except for “limited impact”1 RAS, the possible inadvertent operation or failure to operate of the RAS, resulting from any single RAS component malfunction satisfies

all of the following:”

R6, second bullet item presently reads “Notifying the Reliability Coordinator pursuant to Requirements R5, or”. To be clear, a CAP is only needed if the RAS fails to operate or if during the evaluation of an operation, a deficiency is confirmed. Suggest changing the language of this bullet to “Notifying the Reliability Coordinator of a deficiency or failure to operate pursuant to Requirements R5.2, or”

Use of the word “cannot” in footnote 1 is too restrictive and onerous for excluding a RAS from having to comply with the single component failure requirements in PRC-012-2. We suggest the Footnote 1 be revised to say:

“A RAS designated as “limited impact” has been demonstrated through studies to not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations as a result of inadvertent operation or failure to operate. See Attachment 2 for a description of the limited impact determination by the Reliability Coordinator. A RAS implemented prior to the effective date of this standard that has been through the regional

review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited

	impact for the purposes of Requirement 4, Parts 4.1.3 and 4.1.4." R8 is vague and subject to interpretation. There are references in the supplemental material that suggest verification all of the logic in a RAS PLC on a periodic basis is required and yet in PRC-005, it's clear that there is no need to perform periodic maintenance on relay logic after it is commissioned. R8 also does not consider fully monitored components of the RAS such as in PRC-005. Attachment 1, II.6 language should be modified similar to comment above to capture the possible RAS failure to operate due to a single RAS component malfunction. Suggest new wording: "Documentation describing the System performance resulting from the possible inadvertent operation or failure to operate of the RAS, except for limited impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be limited impact must satisfy all of the following:" Attachment 1, III.3. statement appears to be only applicable to "limited impact" RAS. Wording of this item should be modified to reflect this. A limited impact RAS will still function correctly when a single component failure occurs or when a single component is taken out for maintenance. In all cases, reliability of a RAS scheme is impacted. It is not realistic to expect that reliability will not be compromised. It is unclear what the intent of this statement is.
Document Name:	
Likes:	0
Dislikes:	0

Chris Gowder - Chris Gowder On Behalf of: Tom Reedy, Florida Municipal Power Pool, 6

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

FMPA is confused as to why the drafting team considers 60 full calendar months to be more consistent with PRC-014-0 than 5 calendar years, and views the later as extending the schedule (60 months = 5 years). FMPA's previous suggestion (see below) was not to "extend this schedule", but to make it more consistent with the annual Planning Assessment requirements of the TPL standard. A change to 5 calendar years would allow the Planning Coordinator to conduct their RAS evaluations in conjunction with their Planning Assessment, even if their process concludes in a different month in year 5 than it did in year 1. Requiring 60 calendar months versus 5 calendar years creates an unnecessary compliance burden that does not enhance reliability. The revision process should result in a standard that is more consistent with other active standards than its previous version, especially one that was never approved by FERC.

From the consideration of comments document…

"RAS Periodic Evaluations: Do you agree with the RAS planning evaluation process outlined by Requirement R4? If no, please provide the basis for your disagreement and an alternate proposal.

Selected Answer: Yes

Answer Comment: Recommend changing 60 full calendar months to 5 calendar years, to allow the RAS evaluation to fit within the annual Planning Assessment process which may vary from year to year.

Response: Thank you for your comment.

The drafting team based the 60 full calendar months schedule on the existing PRC -01
five year. . ." The drafting team does not see a convincing reliability reason to further extend this schedule and declines to make the suggested change."

Document Name:

Likes: 0

Dislikes:	0

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC

Group Information

Group Name: LG&E and KU Energy, LLC

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E adn KU energy, LLC	SERC	1,3,5,6
justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6
Chjarlie Freibert	LG&E and KU Energy, LLC	SERC	3
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Dan Wilson	LG&E and KU Energy, LLC	SERC	5

Voter Information

Voter	Segment
Brent Ingebrigtson	1,3,5,6
Entity	**Region(s)**
LG&E and KU Energy, LLC	SERC

Selected Answer:

Answer Comment:

These comments are submitted on behalf of Louisville Gas and Electric Company and Kentucky Utilities Company. ("LG&E/KU"). LG&E/KU are registered in one region (SERC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.

LG&E/KU strongly support the efforts the Standard Drafting Team has undertaken to provide in PRC-012 clear and unambiguous performance expectations and reliability benefits. LG&E/KU agree that the planning, design, periodic review, analysis and testing of SPS/RAS schemes are each essential components of maintaining BES reliability and that revising PRC-012 is a necessary and critical step towards that end.

LG&E/KU note that in Section 4 - Applicability of the latest draft of PRC-012, the functional entity "Planning Coordinator" has replaced "Transmission Planner." LG&E/KU support this change. However, while the current draft standard requires the Planning Coordinator to periodically review SPS/RAS schemes within the PC's planning region, the draft standard provides no role for the PC in approving any corrective action plan(s) developed to mitigate whatever threat(s) to BES reliability the PC's periodic review may have revealed. Moreover, and perhaps more importantly, there is likewise no requirement that the PC approve planned new or modified SPS/RAS schemes to insure consistency with procedures, protocols, and modeling methodology utilized with the relevant planning region. These omissions make it more difficult for the Planning Coordinator to coordinate and integrate the "transmission facility and service plans, resource plans, and protection system plans among the Transmission Planner(s) and Resource Planner(s) within its area of purview."[1]

LG&E/KU recognize that in some larger planning regions the Planning Coordinator ("PC") function may reside within the same organizational entity as the Transmission Owner ("TO") or Reliability Coordinator ("RC") functions. PRC-012, however, should function to promote and maintain BES reliability regardless of how the TO, PC and RC functions are distributed between organizational entities. Accordingly, LG&E/KU offer for the SDT's consideration the following changes to the draft requirements:

Requirement R1

Prior to placing a new or functionally modified RAS in -servic
existing RAS, each RAS -entity sh
Attachment 1 for review to the Reliability Coordinator(s) in consultation with the Planning Coordinator where the RAS is located.

Requirement R2

Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback developed in consultation with the Planning Coordinator to each RAS -entity.

Requirement R3

Prior to placing a new or functionally modified RAS in -servic
existing RAS, each RAS entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to

obtain approval of the RAS from the RAS-entity's Planning Coordinator and each reviewing Reliability Coordinator.

Requirement R5.2

Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s) and Planning Coordinator.

Requirement R6

Each RAS entity shall participate in Planning Coordinator and Reliability Coordinator in developing a Corrective Action Plan (CAP) and submit the CAP to the RAS-entity's Planning Coordinator and Reliability Coordinator(s) within six full calendar months of:

Requirement R7.3

Notify each reviewing Reliability Coordinator and Planning Coordinator if CAP actions or timetables change and when the CAP is completed.

[1] NERC Reliability Functional Model Technical Document — Version 5, at p.10.

Document Name:

Likes:	0
Dislikes:	0

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Information

Group Name: RSC no Con Edison, Hydro Quebec

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
David Burke	Orange and Rockland Utilities	NPCC	3
Wayne Sipperly	New York Power Authority	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7
Kathleen M. Goodman	ISO-New England	NPCC	2
Helen Lainis	Independent Electricity System Operator	NPCC	2
Michael Jones	National Grid	NPCC	3
Silvia Parada Mitchell	NextEra Energy	NPCC	4
Connie Lowe	Dominion	NPCC	4

Voter Information

Voter **Segment**

Ruida Shu	1,2,3,4,5,6,7
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer:

Answer Comment:

R9 as written requires an update to the database to be made every 12 months. The Measure requires evidence that the database was updated. This would not address the situation where no update to the database was required because information did not change.

Reliability Standards usually use the phrase “review the information in the database and update as necessary”. Then the Measure becomes to present evidence that the review occurred and if a change occurred then the database was updated.

Section 4.1.3 reads “Except for “limited impact”1 RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following:” Criteria 4.1.3.1 – 4.1.3.5 follow. Should this requirement also pertain to a failure to operate, which is the more severe consequence of have a single RAS component malfunction? Suggest the following wording change: “Except for “limited impact”1 RAS, the possible inadvertent operation or failure to operate of the RAS, resulting from any single RAS component malfunction satisfies all of the following:”

R6, second bullet item presently reads “Notifying the Reliability Coordinator pursuant to Requirements R5, or”. To be clear a CAP is only needed if the RAS fails to operate or if during the evaluation of an operation, a deficiency is confirmed. Suggest changing the language of this bullet to “Notifying the Reliability Coordinator of a deficiency or failure to operate pursuant to Requirements R5.2, or”

Use of the word “cannot” in footnote 1 is too restrictive and onerous for excluding a RAS from having to comply with the single component failure requirements in PRC-012-2. We suggest the Footnote 1 be revised to say:

“A RAS designated as “limited impact” has been demonstrated by studies to not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations as a result of inadvertent operation or failure to operate. See Attachment 2 for a description of the limited impact determination by the

Reliability Coordinator. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact for the purposes of Requirement 4, Parts 4.1.3 and 4.1.4."

R8 is vague and subject to interpretation. There are references in the supplemental material that suggest maintenance checking all of the logic in a PLC on a periodic basis is required and yet in PRC-005, it's clear that there is no need to perform periodic maintenance on relay logic. R8 also does not consider fully monitored components of the RAS such as in PRC-005.

Attachment 1, II.6 language should be modified similar to comment above to capture the possible RAS failure to operate due to a single RAS component malfunction. Suggest new wording: "Documentation describing the System performance resulting from the possible inadvertent operation or failure to operate of the RAS, except for limited impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be limited impact must satisfy all of the following:"

Attachment 1, III.3 statement appears to be only applicable to "limited impact" RAS. Wording of this item should be modified to reflect this. A limited impact RAS will still function correctly when a single component failure occurs or when a single component is taken out for maintenance. In all cases, reliability of a RAS scheme is impacted. It is not realistic to expect that reliability will not be compromised. It is unclear what the intent of this statement is.

While we support the proposed standard as presented, the word "participate" in Requirements R5, R6 and R8 can lead to confusion and may result in no entities being held responsible for initiating or leading the required tasks. As written, the RAS Entity needs only to participate in such tasks, but it is unclear on whose tasks are they or who leads these tasks.

We suggest remove the word "participate" from R5, R6 and R8 so that the RAS Entity is held responsible for analyzing the RAS operational performance in R5, developing a CAP in R6, and conducting functional test in R8. Note that the wording in the VSLs for R5, R6 and R8 clearly indicates that the RAS Entity is responsible for these tasks. Hence, the word “participate” in the above-mentioned three requirements is unnecessary and confusing.

We respectfully requests the STD to consider its previous comment; we believe that RAS should be reviewed and approved in both the planning and operating horizons by the designated entities within whose area(s) the Facility (ies) the RAS is designed to protect reside.

We believes that the term “in-kind” included in Footnote 4, “Changes to RAS hardware beyond in -kind suggests that the term be clarified such that the reader knows that the replacement of an electromechanical relay with a microprocessor relay is construed as an “in kind” replacement, as the drafting team noted in their December 15th presentation. The concept of “In-kind” replacement could be taken a step further. For example, a discrete ladder logic circuit that includes contacts, overcurrent and voltage relays could be replaced entirely inside the software logic of a multifunction device. From a black-box viewpoint, the old and new RAS would be identical in function. We also suggests for additional consideration that the replacement of many discrete components with a single multifunction component also be considered an “in kind” replacement so long as for a given set of inputs the “black box” produces the same outputs as the previous RAS would. In the case of a breaker failure event, the Standards Drafting Team “SDT” indicates the need for RAS redundancy even though that would be a double failure event (failure of the RAS and failure of the breaker). We suggests that it is sufficiently redundant to use the existing breaker failure relay (non-redundant) to initiate both RAS schemes. This can be accomplished by each RAS using a different contact off the breaker failure relay that was separately fused.

We suggests the SDT consider using a consistent measure of time, either calendar months or full calendar days, for responding and reporting. For example, Requirement 2 states: Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1, shall, within **four** **- f** **calendar months** of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS -entity.” Whereas Requirement 4 states that: “Each RAS entity, within **120** **full calendar days** of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall:”

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

Reclamation appreciates the drafting team’s consolidation of the terms RAS - owner and RAS -
Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS.

Reclamation also agrees with the drafting team’s update to Requirement R6 that each RAS -
this collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service.

Reclamation supports the proposed change to the definition of SPS.

Document Name:

Likes: 0

Dislikes: 0

Rich Hydzik - Rich Hydzik On Behalf of: Bryan Cox, Avista - Avista Corporation, 5, 3, 1
Scott Kinney, Avista - Avista Corporation, 5, 3, 1

Selected Answer:

Answer Comment:

PRC-012-2 includes some very positive changes for the industry.

In R4.1.3, footnote 1 defines a “limited impact” RAS which does not require designing to a “no single point of failure” standard. It is a good thing to have this defined in a NERC standard.

Functional testing requirements defined to be every six years (R8). This is reasonable.

Evaluation of the need and performance of a RAS every six years is reasonable (R4).

However, there are concerns that prevent an “affirmative” vote for this standard.

The Reliability Coordinator is a function is defined as:

“The entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator’s vision.”

This supports the concept of the RC reviewing the functionality and intended use of a RAS. However, a detailed RAS review also includes a design review of the RAS components and overall system design. This includes, but is not limited to, substation engineering, relay protection and design, telecommunication design and performance, and individual TOP operating practices. The RC’s are familiar with the overall operation and performance of the BES. The RC’s skill set generally does not include those technical specialties required for a detailed review of the design of a RAS.

This follows that the evaluation of a RAS misoperation should be performed by a different entity than the RC. While the RC certainly can evaluate the performance of the RAS and identify that a misoperation occurred, the RC’s skill set does not allow for a thorough review of the RAS problem or potential solutions. Further, implementing a Corrective Action Plan under the supervision of the RC does not seem appropriate. This places the RC in an engineering, maintenance, and enforcement role that does not appear to be with the RC function.

The intent of the standard is sound. Implementation among the Reliability Entities needs further development.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Degraded RAS

As Texas RE mentioned in the comments for the initial ballot, Texas RE recommends a requirement to report the degraded RAS to the RC. Texas RE noticed the referenced Standards/Requirements (i.e., Supplemental Material indicates PRC-001 R6 and TOP-001-2 R5) are either being retired or are not explicit enough to ensure that the reliability of the system is maintained for those who should have situational awareness. PRC-001 R6 is being retired and translated to TOP-001-3 R10 and R11 which applies to ONLY the TOP and BA not the RC. While TOP-003-3 states a BA and TOP "shall distribute its data specification to entities that have data required by the" respective functions and analysis (e.g., Real-time monitoring, Operational Planning Analyses), there is no requirement to provide the RAS status to the RC.

Requirement R8

Texas RE is concerned introducing a six year functional testing requirement for a RAS is too long to ensure reliability of a system because reliability is at stake for the RAS to be in place. This extended timeframe may disregard PRC-005 components that may have shorter timeframes for maintenance or cause confusion to the entities responsible for said maintenance. While the RAS-entity will have PRC-005 obligations, it should not be considered the same as functional testing of the RAS if the PRC-005 components are ignored, overlooked, or not reviewed. Coordinated functional testing should be required for multi-RAS-entity owned RASs. Without coordination, there is not a clear reliability path to ensure overall performance and the proper operation of ALL RAS components.

Texas RE seeks clarity on the rationale for Requirement R8. It does not seem to reflect a coherent approach to reliability when discussing resetting the "test interval clock for that segment". The Requirement is written for the RAS not segments of the RAS. The phrase "of its" that was added increases ambiguity and may cause confusion among RAS-entities in a multi-owned component RAS. Texas RE recommends requiring coordination of functional testing for RASs with components owned by more than one RAS-entity. Individualized non-coordinated functional testing of RAS components will not be a functional test of the RAS.

Full Calendar Months

The SDT introduces a new term “full calendar months” that is not defined and is inconsistent with other Reliability Standards. Texas Re recommends the SDT provide the definition within the auspices of the Standards process while considering other definitions already in place (such as “Calendar Year” in PRC-005-2).

Corrective Action Plan

Texas RE recommends revising PRC-12-2, R7 to place at least minimal criteria around modifications to Corrective Action Plans (CAP) or corresponding CAP timetables. As currently drafted, PRC-12-2, R7 could be interpreted to permit RAS-entities to perpetually update their CAPs if “actions or timetables change” and then merely notify the RC of such changes. Texas RE recommends that the SDT consider some minimal criteria that RAS-entities must satisfy in order to update a CAP under PRC-12-2, R7.2. For instance, PRC-12-2, R7.2 could be revised to read: “Update the CAP for any reasonable changes in the required actions or implementation timetable.” In turn, PRC-12-2, R7.3 could be revised to read: “Notify each reviewing Reliability Coordinator and provide a reasoned justification for changes in CAP actions or timetables, and notify each reviewing Reliability Coordinator when the CAP is completed.”

RAS-entity definition

The current draft of PRC-12-2 defines the term “RAS-entity” in the Technical Justifications for Requirements section. Texas RE recommends that the SDT consider incorporating this definition into the language of PRC-12-2 itself or into the NERC Glossary of Terms.

Misoperations

In Requirement R5, what constitutes a RAS operation or misoperation? The NERC SPCS created a draft template in 2014 for reporting RAS operations and misoperations where they defined a misoperation as “Failure to Operate”, “Unnecessary Operation”, “Unintended System Response”, and “Failure to Mitigate”. These were draft terms and have not been incorporated into any Standard or the NERC Glossary. Arming and disarming of a RAS were not included in the SPCS RAS template. The items listed in 5.1.1 through 5.1.4

somewhat mirror the SPCS RAS template, is it the SDT's intent that 5.1.1 through 5.1.4 are intended to be the definition of a RAS operation/misoperation? If so, Texas RE suggests these would be better suited in the NERC Glossary than within the Standard.

Also reporting of Misoperations for Protection Systems will be contained with the Section 1600 Data Request for PRC-004. There is no requirement within PRC-012 or the Section 1600 data request for reporting Misoperations of a RAS to the Regional Entities or NERC. Texas RE recommends the SDT consider this.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

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Selected Answer:

Answer Comment:

1. Numerous entities, including TVA, have previously commented that the responsibility for reviewing and approving new or functionally modified RAS schemes belongs with the Planning Coordinator and not the Reliability Coordinator. According to the NERC Reliability Functional Model - Version 5, the Planning Coordinator is defined as the, "…entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facilities and services plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas." The model specifically includes the evaluation of transmission facilities in the planning horizon. Conversely, the Reliability Coordinator is responsible for maintaining the *Real-time* reliability of the Bulk Electric System. It was never contemplated that the Reliability Coordinator would have oversight over the planning of the Bulk Electric System or the entities responsible for Bulk Electric System planning. The drafting team's response to TVA's comments states that the Reliability Coordinator has the "widest-area reliability perspective of all functional entities" and that the "NERC Functional Model is a guideline" and does not preclude the drafting team from addressing functions not described in the Functional

	Model. From TVA's perspective, however, the proposed standard, as written, is in direct conflict with the Functional Model, and requires a compelling reason to justify the deviation. The facts that there are fewer Reliability Coordinators (as opposed to Planning Coordinators) and that the Reliability Coordinators have the "widest-area view" do not support a significant deviation from the Functional Model. Moreover, such analysis would beyond the normal Reliability Coordinator functions, the Reliability Coordinators would not have the expertise to conduct RAS analysis in the planning horizon. Simply put, Reliability Coordinators do not have trained personnel or the appropriate tools to complete a comprehensive assessment. Planning Coordinators have oversight over all other aspects of planning of the Bulk Electric System, and there is no reason to treat Remedial Action Schemes differently. R6 requires the "RAS-entity" to develop Corrective Action Plans if there is a deficiency in its 5-year RAS evaluation (R4), its post-event analysis (R5), or its 6-year functional testing (R8), and to submit those Corrective Action Plans to the Reliability Coordinator for review. The proposed standard, however, does not give the Reliability Coordinator any authority to approve or deny the Corrective Action Plan. If the Corrective Action Plan is inadequate or changes the RAS to cause a negative impact on a wider area of the BES, the Reliability Coordinator must be able to reject the Corrective Action Plan and require a revised plan.
Document Name:	
Likes:	0
Dislikes:	0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer:

Answer Comment:

TANC appreciates the drafting team's response to our prior comments and the corresponding changes to the standard regarding the potentially overlapping responsibilities of multiple Transmission Owners, Generator Owners and Distribution Providers that each own portions of a single RAS. In its response to TANC's prior comments, the drafting team stated that each RAS-entity "is responsible only for its RAS components." The second draft of the standard is not so clear on this issue, however, as the requirements only refer to each RAS-entity's responsibility for "its RAS". TANC requests that NERC replace "its RAS" with "its RAS components" in the requirements of the standard to clarify the responsibilities of each party. TANC believes that inserting this distinction into the language of the requirements would more clearly convey that multiple parties may have compliance responsibility for their respective "components" of a single RAS, but each party is not responsible for the entirety of the RAS.

TANC notes that the "Reliability Standard PRC-012-2 Remedial Action Schemes Question & Answer Document" document dated November 2015 appears to incorrectly reference the Transmission Owner (TO) function in the first paragraph of Section 3. References in that paragraph were made to TO roles and responsibilities that are purportedly established within standards TOP-001-3 and IRO-005-4, but those two standards establish roles and responsibilities for the Transmission Operator (TOP) function, not the TO function.

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Independent Electricity System Operator - 2 - NPCC

Selected Answer:

Answer Comment:

While we support the proposed standard as presented, the word "participate" in Requirements R5, R6 and R8 can lead to confusion and may result in no entities being held responsible for initiating or leading the required tasks. As written, the RAS Entity needs only to participate in such tasks, but it is unclear on whose tasks are they or who leads these tasks.

We suggest to remove the word "participate" from R5, R6 and R8 so that the RAS Entity is held responsible for analyzing the RAS operational performance in R5, developing a CAP in R6, and conducting functional test in R8. Note that the wording in the VSLs for R5, R6 and R8 clearly indicates that the RAS Entity is responsible for these tasks. Hence, the word "participate" in the above-mentioned three requirements is unnecessary and confusing.

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3
Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer:

Answer Comment:

While Hydro One Networks Inc. is generally in support of the direction the standard takes and although the third revision (Draft 2- November 2015) presents improvement (with the introduction of the concept of "limited impact RAS" and recognition of RAS typing), requirement R8 and several choices in wording remain a concern. Hydro One believes that a level of testing similar to that required in the PRC-005 series would be more appropriate for R8. With a level of testing specified in Comment #1 below, a high VRF, similar to that designated in the PRC-005 series would be appropriate and hence although Hydro One has cast a negative ballot on the standard, we are in support of the poll associated with the VRFs and VSLs. We hope the comments provided below will be of added value to the drafting team:

1. R8 is vague and subject to interpretation. There are references in the supplemental material that suggest maintenance and checking of all the logic in a PLC on a periodic basis is required, and yet, in PRC-005, it is clear that there is no need to perform periodic maintenance on relay logic. For monitored components, such as microprocessor relays, the "verification of settings [as] specified" in PRC-005 (i.e., performing a settings compare) should be sufficient rather than implying that all logic needs to be re-verified. For RAS not designated as limited-impact, R8 does not distinguish between monitored and unmonitored components of the RAS such as distinguished in PRC-005, which would allow a RAS-entity to have a 12-year maintenance interval for monitored components.

2. R5.1 – The usage of the term "*[p]articipate*" does not define accountability. The standard should clearly identify who is accountable for what activity. For consistency, we suggest using verbiage similar to that used in PRC-004-4's description of accountabilities in the case of owning Shared Protection Systems.

3. R5.1.3 & R5.1.4 are related to performance of RAS and its impact on the BES. This assessment is better suitable for the PC or RC to conduct.

4. R5.2 – "*Each RAS-entity shall provide results (…) to RC*". In the case that a RAS is owned by more than one entity, it is unclear from the verbiage which entity is accountable to communicate with the RC and maintain evidence of such activity. The standard should clearly identify who is accountable for what activity. For consistency, we suggest using verbiage similar to that used in PRC-004-4's description of accountabilities in the case of owning Shared Protection Systems.

5. R6 - " *Each RAS-entity shall participate*" - Similar to the comments submitted above for R5, the usage of the term "*[p]articipate*" does not define accountability. The standard should clearly identify who is accountable for what activity. For consistency, we suggest using verbiage similar to that used in PRC-004-4's description of accountabilities in the case of owning Shared Protection Systems.

6. "*Each RAS-entity shall submit the CAP to RC*" - Similar to the comments submitted above for R5, in the case that a RAS is owned by multiple entities, it is unclear from the verbiage which entity is accountable to communicate with the RC and maintain evidence of such activity.

7. R5 – It is unclear from the wording whether the RAS-entity would "*[p]articipate in analyzing the RAS operational performance*" with the RC, or only mutually agree upon a schedule for such activity with the RC.

8. R4.1.4 - When a RAS is used to respond to an event, e.g. category P1 in TPL-001-4, its failure should be considered to be a more severe event, just as in TPL-001-4, the failure of a breaker or protection relay following a P1 event is recognized as “Multiple Contingency” (category P3 and P4). For this reason, the system performance with a RAS failure should not be required to meet the exact same requirements as those for the original event (defined in TPL-001-4). Therefore, we suggest deleting R4.1.4 and instead revising R4.1.3 to read “Except for “limited impact”1 RAS, the possible inadvertent operation of the RAS, or failure of the RAS to operate, resulting from any single RAS component malfunction satisfies all of the following:”

9. RAS-entity: The standard should clearly define accountabilities in the case of a RAS scheme being owned by multiple entities.

10. R2 – We suggest specifying which entity the RC will be mutually agreeing upon a schedule with: “*on a schedule mutually agreed upon with the RAS-entity,….*”

Hydro One Networks Inc. also generally supports the comments the NPCC has submitted.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

R2: BPA maintains that the allowance of up to four full calendar months for the RC to perform the RAS review is unreasonable and not in line with current regional practice.

Currently in WECC, RAS information for new or functionally modified schemes (this information is equivalent to Attachment 1 and 2) is provided two weeks in advance of scheduled WECC RAS RS meetings. At those meetings, all details of the RAS are presented, reviewed, and approved/disapproved. The review is at the final stages of the design process, just prior to construction/energization. By requiring Attachment 1, and Attachment 2, and allowing the RC four full calendar months review time, it appears that four months is being added to the entire process of placing a RAS in service. This additional four month delay may constrain the energization of variable generation resources.

Regarding Attachment 2: “**The RC review is not limited to the checklist items and the RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS.”** BPA believes this presents an open-ended opportunity to increase the four month review window, because you can’t go in service without prior approval of the RAS.

Attachment 2. II. 2. “**The timing of RAS actions(s) is appropriate to its BES performance objectives**.” This makes sense, but often timing of a RAS cannot be proven until the RAS is built and functionally tested. Historically in WECC, you are aware of the timing constraints required for RAS operation, you provide an estimate of the timing, and you’re provided “conditional approval” to go operational with a future action item presented to the WECC RAS RS that validates the timing is within constraints. Item 2 implies that a RAS-entity has to prove the timing prior to going in service, which isn’t reasonable. That basically means that the RAS-entity has to build the scheme, test it, and then go get it approved.

Attachment 2. II. 4. “**The RAS design facilitates periodic testing and maintenance**.” BPA believes this is subjective; does this mean that the RC would require a standard method for periodic testing and maintenance? This appears open to interpretation.

The four full calendar months appears to create the opportunity for a large increase in workload and back and forth discussion between the RC and the utility designing the RAS.

R3: BPA proposes the requirement allow for conditional approval.

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - PRC-012-2 Project

Group Member Name	Entity	Region	Segments
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Ryan Strom	Buckeye Power, Inc.	RFC	4
Matt Caves	Western Farmers Electric Cooperative	SPP	1,5
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc. and Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Kevin Lyons	Central Iowa Power Cooperative	MRO	1
Mike Brytowski	Great River Energy	MRO	1,3,5,6

Voter Information

Voter	Segment
Ben Engelby	6
Entity	**Region(s)**
ACES Power Marketing	

Selected Answer:

Answer Comment:

(1) We agree with the SDT’s consolidation of the reliability objectives of the six existing RAS/SPS related standards into one standard PRC-012-2.

(2) The SAR for revising TPL-001-4 for single points of failure may overlap with PRC-012-2. We recommend the SDT meet with the SAR team to discuss the

scope and potential for overlap that could lead to double jeopardy. We recommend that NERC staff also research this issue.

(3) RAS-entity causes confusion for entities that have joint ownership of a RAS. We recommend the SDT develop guidance to support the requirements and expectations for joint owners to meet compliance. For RAS with multiple RAS-entities, who is responsible for overall coordination to assure complete and consistent data submittals in order to meet compliance with this standard? The SDT has left this silent, which may result in joint entities not cooperating, not sharing documentation, etc.

(4) Corrective Action Plans need to be clarified as to what triggers would qualify as a “deficiency” that would require a CAP to be developed. We also have concerns relating to coordination of CAPs that are developed for a jointly-owned RAS.

(5) We believe the VSLs for this standard could be better defined. The incremental scale between one criteria (e.g., R4 has 60, 61, 62, 63 calendar months for ranges from Lower to Severe) to the next for several VSLs are too condensed. We also believe a graduated scale for Requirements R1 and R3 could be provided.

(6) We agree that the RC is the best-suited entity to perform the RAS reviews. However, we recommend that the SDT actively work with RCs to ensure they are aware of the proposed requirements and have the resources to support them.

(7) We agree that the PC has a broader view compared to the TP and is the proper entity for RAS periodic evaluations.

(8) Finally, we ask NERC to consider the holiday schedule when posting standards for comment. There are several industry groups that coordinate comments a week or two prior to final submission to the SDT, and having to coordinate comments over the holidays is difficult with vacation schedules. We ask the drafting teams to consider delaying posting so the deadline is the second or third week in January, allowing the industry groups enough time to coordinate during the weeks prior to the due date.

(9) Thank you for the opportunity to comment.

Document Name:

Likes: 0

Dislikes: 0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Group Information

Group Name: AECI

Group Member Name	Entity	Region	Segments
Mark Ramsey	N.W. Electric Power Cooperative, Inc.	SERC	1
John Stickley	N.W. Electric Power Cooperative, Inc.	SERC	3
Kevin White	Northeast Missouri Electric Power Cooperative	SERC	1
Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	SERC	3
Michael B Bax	Central Electric Power Cooperative	SERC	1
Adam M Weber	Central Electric Power Cooperative	SERC	3
Denise Stevens	Sho-Me Power Electric Cooperative	SERC	1
Jeff L Neas	Sho-Me Power Electric Cooperative	SERC	3
Walter Kenyon	KAMO Electric Cooperative	SERC	1
Theodore J Hilmes	KAMO Electric Cooperative	SERC	3
Phillip B Hart	Associated Electric Cooperative Inc.	SERC	1
Todd Bennett	Associated Electric Cooperative Inc.	SERC	3
Matt Pacobit	Associated Electric Cooperative Inc.	SERC	5
Brian Ackermann	Associated Electric Cooperative Inc.	SERC	6

Voter Information

Voter	Segment
Phil Hart	1

Entity	Region(s)
Associated Electric Cooperative, Inc.	

Selected Answer:

Answer Comment: AECI is in agreement with multiple commenters who have issue with this current version.

Document Name:

Likes: 0

Dislikes: 0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment:

ERCOT supports the comments submitted by the IRC SRC and provides these additional comments.

As noted above, ERCOT no longer uses the “Type 2” RAS designation, and this reference should be removed from the footnotes and rationale boxes in this draft standard.

R6 should be reworded to clarify compliance obligations for the RAS-entity. ERCOT suggests the following language:

“Each RAS -e
CAP to its reviewing Reliability Coordinator(s) within six full calendar months of:...."

Additionally, the references to days and months should be standardized. There are references to 60 calendar months, 6 calendar months, and 120 calendar days. The SDT should consider expressing all of these time periods in the same units—using either months or days to maintain consistency throughout the standard.

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer:

Answer Comment:

There needs to be some mechanism in place (possibly a requirement) to ensure that RAS functionality and coordination issues are addressed in response to physical changes to the system, e.g., removing or adding transmission or generation Facilities. A reliability gap can be created if the physical system is changed, but RAS are not updated or modified in response to those physical system changes. Without a functional modification to the RAS it would not perform according to its intended design. The five year review process cannot be relied upon to address these scenarios, as it would result in long-term exposure to reliability risks.

Example scenario:

{C}· A RAS exists in an area to prevent voltage collapse

{C}· An entity retires a generation Facility which is associated with the RAS

{C}· The RAS is not updated to account for the retirement of the generation Facility

{C}· The RAS is rendered ineffective for preventing voltage collapse

{C}· This condition is not discovered until the PC performs its 5-year review

{C}· Until the PC performs its 5-year review, the system is vulnerable to voltage collapse due to RAS ineffectiveness

Both R4.1.4 and Attachment 1, section III, item 4 use the same confusing language, “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 -00 those required for the events and conditions for which the RAS is designed.” Though similar language is used in the currently effective set of reliability standards, it is confusing and unclear. We recommend clarifying the language and/or providing examples in an application guideline as part of the standard itself that might help the reader understand the meaning of and intent behind this language.

In R2 RC is required to follow Attachment 2 for the evaluation, what is the required evaluation for the PC in R4? Is it Attachment 2 as well?

For R5 when a RAS operation, failure to operate, or mis-operation occurs, and a deficiency is identified, the RAS should be removed from service until the CAP is implemented.

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2

Voter Information

Voter	Segment
Jason Smith	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	MRO,SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Consideration of Comments

Project Name: 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes | PRC-012-2

Comment Period Start Date: 11/25/2015

Comment Period End Date: 1/8/2016

Associated Ballots: 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes PRC-012-2 AB 2 ST and 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes Definition IN 1 DEF

There were 46 responses, including comments from approximately 150 different people from approximately 98 different companies representing 9 of the 10 Industry Segments as shown on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Howard Gugel (via email) or at (404) 446-9693.

The drafting team made the following changes to the draft standard and implementation plan based on stakeholder comments.

Reliability Standard PRC-012-2

Requirements

Requirement R4

Revised the periodic evaluation time period from "at least once every 60 full calendar months" to "at least once every five full calendar years."

Included a provision requiring limited impact RAS be included in the periodic evaluation to ensure they still qualify for the limited impact designation.

Requirement R6

Revised second bullet for more specificity to read: "Notifying the Reliability Coordinator *of a deficiency* pursuant to Requirement R5, *Part 5.2*, or".

Measures, VSLs, and Attachments

Revised to be consistent with and complement the revised requirements.

The timing of RAS operations was moved from the Implementation section to the Design section of Attachment 2 for clarity.

Rationale Boxes and Supplemental Material

Revised to complement the modified requirements and provide additional clarity.

Footnotes

Revised footnote 1 by removing the provision concerning the initial consideration of WECC Local Area Protection Scheme (LAPS) and NPCC Type III RAS as limited impact RAS upon the effective date of PRC-012-2 (moved provision to Implementation Plan).

Clarifying edits made to footnote 2 regarding functional modifications.

Implementation Plan

Limited Impact RAS

Included the provision (previously in footnote 1) concerning the initial consideration of WECC Local Area Protection Scheme (LAPS) and NPCC Type III RAS as limited impact RAS upon the effective date of PRC-012-2.

Requirements R4 and R8

Revised language for the initial performance of obligations under Requirements R4 and R8 for consistency and clarity.

Requirement R9

Revised the Requirement R9 provision to clarify that the initial obligation for a Reliability Coordinator that does not have a RAS database is to establish one (RAS database) by the effective date of PRC-012-2; i.e., during the thirty-six (36) month implementation period.

Questions

1. **Limited impact designation: Within the RAS review process of PRC-012-2, the drafting team included a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process. Do you agree with the provision that RAS can be designated as "limited impact"? If no, please provide the basis for your disagreement and an alternate proposal.**

2. **Implementation Plan for PRC-012-2: The drafting team revised the Implementation Plan to provide clarity and to lengthen the implementation period to thirty-six months to provide the responsible entities adequate time to establish the new working frameworks among functional entities. Do you agree with the revised Implementation Plan? If no, please provide the basis for your disagreement and an alternate proposal.**

3. **Revised Definition of "Special Protection System" and its Implementation Plan: The drafting team revised the definition of "Special Protection System" to cross-reference the revised definition of "Remedial Action Scheme". The Implementation Plan for the revised definition of "Special Protection System" aligns with the effective date of the revised definition of "Remedial Action Scheme". Do you agree with the proposed definition and its implementation plan? If no, please provide the basis for your disagreement and an alternate proposal.**

4. **If you have any other comments that you haven't already provided in response to the above questions, please provide them here.**

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

The drafting team appreciates the feedback that stakeholders provided on the previous posting. Draft 3 of PRC-012-2 is a quality results based standard that will promote reliability thanks to your participation. The drafting team revised the standard and its implementation plan, making clarifying changes to both documents. Responses to the most prevalent comments received for each question are located immediately below the question in this document. Responses to individual comments are not required for a failed additional ballot in accordance with sections 4.12 and 4.13 of the Standards Process Manual. If you have a specific comment that you would like to discuss, please contact the Standards Developer, Al McMeekin at 404-446-9675 or via email Al McMeekin. Please provide your comment, your contact information, and a convenient date and time for a discussion.

1. ***Limited impact designation: Within the RAS review process of PRC-012-2, the drafting team included a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process. Do you agree with the provision that RAS can be designated as "limited impact"? If no, please provide the basis for your disagreement and an alternate proposal.***

Limited impact designation

RAS are unique and customized assemblages of protection and control equipment that vary in complexity and impact on the reliability of the BES. In recognition of these differences, within the structure of Requirements R1-R4 of PRC-012-2, a RAS can be proposed by the Planning Coordinator and RAS-entity to be recognized as limited impact. The RAS-entity may at any time, submit Attachment 1 information to the reviewing Reliability Coordinator(s) that includes the technical justification (evaluations) documenting that the System can meet the performance requirements (specified in Requirement R4, Parts 4.1.4 and 4.1.5) resulting from a single RAS component malfunction or failure, respectively. The reviewing Reliability Coordinator(s) is the final arbiter for determining whether a RAS qualifies for the limited impact designation. The limited impact designation is available to any RAS in any Region provided the reviewing RC determines the RAS poses a low risk to BES reliability.

To achieve the limited impact designation, a RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. The limited impact designation is modeled after the Local Area Protection Scheme (LAPS) classification in WECC (Western Electricity Coordinating Council) and the Type 3 classification in NPCC (Northeast Power Coordinating Council). The following information describing the aforementioned WECC and NPCC RAS is excerpted from the respective regional documentation .The drafting team notes that the information below represents the state of the WECC and NPCC regional processes at the time of this standard development and is subject to change before the effective date of PRC-012-2.

WECC: Local Area Protection Scheme (LAPS)

A Remedial Action Scheme (RAS) whose failure to operate would NOT result in any of the following:

- Violations of TPL-001-WECC-RBP System Performance RBP,
- Maximum load loss ≥ 300 MW,
- Maximum generation loss ≥ 1000 MW.

NPCC: Type III

An SPS whose misoperation or failure to operate results in no significant adverse impact outside the local area.

In recognition that the drafting team modeled the limited impact designation after the WECC and NPCC classifications, each RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type 3 in NPCC, will be recognized as a limited impact RAS upon the effective date of PRC-012-2 and is subject to all applicable requirements.

To propose an existing RAS (a RAS implemented prior to the effective date of PRC-012-2) be designated as limited impact by the reviewing RC, the RAS-entity must prepare and submit the appropriate Attachment 1 information that includes the technical justification (evaluations) documenting that the System can meet the performance requirements (specified in Requirement R4, Parts 4.1.4 and 4.1.5) resulting from a single RAS component malfunction or failure, respectively.

There is nothing that precludes a RAS-entity from working with the reviewing RC during the implementation period of PRC-012-2, in anticipation of the standard becoming enforceable. However, even if the reviewing RC determines the RAS qualifies as limited impact, the designation is not relevant until the standard becomes effective. Until then, the existing regional processes remain in effect as do the existing RAS classifications or lack thereof.

Additionally, the drafting team recognizes that System changes occur that could potentially alter the effect of a limited impact RAS (increasing the reliability impact) on the BES. To address this issue, the drafting team added a provision in Requirement 4 that explicitly requires the periodic evaluation of limited impact RAS to verify the limited impact designation remains applicable. Requirement 4, Part 4.1.3 reads: "For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations."

John Fontenot - Bryan Texas Utilities - 1

Selected Answer: Yes

John Falsey - Invenergy LLC - 3 - FRCC,MRO,WECC,TRE,NPCC,SERC,SPP,RFC

Selected Answer: Yes

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5 - RFC	
Selected Answer:	Yes
Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1	
Selected Answer:	Yes
Thomas Foltz - AEP - 5	
Selected Answer:	Yes

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment: The references to “limited impact” pose significant potential for confusion and impact reliability through ambiguity as currently documented. As written, the term “limited impact” is documented an unofficial definition within a single standard.

Response:

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment: Although we agree there is a concern that the availability of the "limited impact" definition may lead to overuse of this option.

Response:

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	**Entity**	**Region**	**Segments**
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6

Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5
Amy Casucelli	Xcel Energy	MRO	1,3,5,6

Selected Answer: Yes

Terry BIlke - Midcontinent ISO, Inc. - 2

Selected Answer: Yes

Randi Heise - Dominion - Dominion Resources, Inc. - 5

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: Yes

Amy Casuscelli - Amy Casuscelli On Behalf of: Peter Colussy, Xcel Energy, Inc. , 6

Selected Answer: Yes

Answer Comment: We appreciate the SDT's responsiveness to our comment in the previous posting advocating the provision of "limited impact" RAS.

Response:

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment: Tri-State supports the introduction of the concept of "limited impact".

Response:

Laura Nelson - IDACORP - Idaho Power Company - 1

Selected Answer: Yes

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Selected Answer: Yes

Answer Comment:

PSEG supports the concept of a limited impact RAS designation within PRC-012-2 provided that it is defined and made available to all RAS entities.

PSEG wishes to note that the criteria for the limited impact designation proposed in draft# 2 of PRC-012-2 are not consistent with the term as it was defined in the NERC SPCS report *"Special Protection Systems (SPS) and Remedial Action Schemes (RAS): Assessment of Definition, Regional*

	Practices, and Application of Related Standards" dated April, 2013. Under that report, a SPS/RAS has a limited impact to the BES if failure or inadvertent operation of the scheme *does not result* in any of the following: Non-Consequential Load Loss ≥ 300 MW; Aggregate resource loss (tripping or runback of generation or HVdc) > the largest Real Power resource within the interconnection; Loss of synchronism between two or more portions of the system each including more than one generating plant; or Negatively damped oscillations. If none of the four results are projected to occur, the SPS is classified as having a limited impact on the BES. While PSEG agrees with the existing NPCC, ERCOT, and WECC limited impact designations, PSEG also believes that one NERC-wide limited impact RAS criteria should be included in PRC-012-2 for new limited impact designations. While PSEG does not advocate any specific limited impact RAS criteria, it does note that the cited SPCS report was approved by the NERC Planning Committee. Any RAS that meets such criteria, whether existing or proposed, should receive limited impact designation. Finally, second draft of PRC-012-2 does not provide an affirmative mechanism for an existing RAS to be classified as limited impact. In order for such a review take place under R2, a RAS-entity must initiate

the review (under R1) when: "…*placing a new or functionally modified RAS in-service or retiring and existing RAS*". Therefore, under our reading of the current draft of PRC-012-2, existing RASs which are not undergoing functional modification do not have an opportunity to be reviewed for a limited impact designation, and R1 should be modified to allow such RAS entities to seek designation for existing RASs as "limited impact." To facilitate such analysis, PSEG's comments in Q4 request that the RAS entity's Planning Coordinator have obligations under R1 to perform the studies related to a RAS's performance that is required in Attachment 1.

Response:

Likes:	5	PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla PSEG - PSEG Fossil LLC, 5, Kucey Tim Long Island Power Authority, 1, Ganley Robert PSEG - Public Service Electric and Gas Co., 1, Smith Joseph PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
Dislikes:	0	

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: Yes

William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2

Selected Answer: Yes

Answer Comment: The Standards Drafting Team (SDT) states a RAS which is "…new or functionally modified RAS implemented after the effective date…" can be recognized as "limited impact." Can a RAS currently in place and not within the Types already "grandfathered" by this standard (e.g., Type 3 in NPCC, Type 2 in ERCOT), become recognized as "limited impact?" We request the SDT provide more clarity on the process for determining "limited impact" on existing RASs.

Response:

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer:	Yes
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Selected Answer:	Yes
Answer Comment:	Tacoma Power appreciates this provision.
Response:	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC	
Group Name:	Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Yes

Andrew Pusztai - American Transmission Company, LLC - 1

Selected Answer: Yes

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Selected Answer: Yes

Answer Comment: The SDT states a RAS which is "…new or functionally modified RAS implemented after the effective date…" can be recognized as "limited impact". Can a RAS currently in place and not within the Types already "grandfathered" by this standard, become recognized as "limited impact"? If so, what is the process?

Response:

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Selected Answer: No

Answer Comment: Please see response to Question #4.

Response:

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1

Selected Answer: Yes

Steve Wenke - Avista - Avista Corporation - 5

Selected Answer: Yes

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: Yes

Mark Kenny - Eversource Energy - 3

Selected Answer: Yes

Chris Gowder - Chris Gowder On Behalf of: Tom Reedy, Florida Municipal Power Pool, 6

Selected Answer: Yes

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Name: RSC no Con Edison, Hydro Quebec

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1

Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
David Burke	Orange and Rockland Utilities	NPCC	3
Wayne Sipperly	New York Power Authority	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7

Kathleen M. Goodman	ISO-New England	NPCC	2
Helen Lainis	Independent Electricity System Operator	NPCC	2
Michael Jones	National Grid	NPCC	3
Silvia Parada Mitchell	NextEra Energy	NPCC	4
Connie Lowe	Dominion	NPCC	4

Selected Answer: Yes

Erika Doot - U.S. Bureau of Reclamation - 5

Selected Answer: Yes

Rich Hydzik - Rich Hydzik On Behalf of: Bryan Cox, Avista - Avista Corporation, 5, 3, 1
Scott Kinney, Avista - Avista Corporation, 5, 3, 1

Selected Answer: Yes

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Selected Answer:	No
Answer Comment:	Texas RE does not agree with the provision that a RAS can be designated as “limited impact”. Moreover, Texas RE recommends the STD reconsider and treat all RASes equally, that affect the reliability of the Bulk Electric System (BES). Texas RE is concerned the proposed criteria for determining a “limited impact” RAS is vague and ambiguous (e.g. “… BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations) which may lead to the approval of a significant number of “limited impact” RASes on the BES, posing a potential risk to reliability. Specifically, the potential risks are that the reduced reliability-related considerations for the Reliability Coordinator (i.e. Attachment 2) and the limited evaluation performed by the Planning Coordinator (i.e. Requirement 4) pertaining to “limited impact” RASes may lead to potential reliability gaps on the BES. In the ERCOT region, the “Type 1” and “Type 2” designations were removed from the regional operating guides in February 2014, therefore, there is no longer a regional criteria for “limited” or “wide-area” impact as referred to in R4.1.3. As one of the goals of this project

	was to eliminate the “fill-in-the-blank” requirements, it seems inappropriate to refer to regional criteria within the standard as it does in footnotes 1, 3, 5, and 6. Texas RE requests the SDT remove that information from the footnotes.
Response:	

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Selected Answer:	Yes

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:	Yes
Answer Comment:	Florida Power & Light appreciates the efforts of the Standard Drafting Team in revising PRC-012-2, however we have concerns on the interpretation of “limited impact” as stated in PRC-012-2 standard. In many cases, RAS’s that are classified as “limited impact” may have a

	larger than expected impact due to system changes. As an example, see page 8 of the NPCC Reliability Reference Directory #7 – Special Protection Systems. NPCC states that "it should be recognized that a Type III SPS may, due to system changes become Type 1 or Type II". To ensure uniform application, we recommend the footnote in Requirement 4 be modified as follows: "…RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations for the system conditions considered in the latest TPL-001-4 stability assessment."
Response:	
Eric Olson - Transmission Agency of Northern California - 1	
Selected Answer:	Yes

Mark Wilson - Independent Electricity System Operator - 2 - NPCC

Selected Answer:	Yes

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3 Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer:	No
Answer Comment:	While Hydro One supports the newly introduced designation of "limited impact" RAS, we feel that its definition should instead read as shown below, in order to ensure that future in-serviced RAS that will be designated by a regional review process as Type 3 (NPCC), Type 2 (ERCOT), or LAPS (WECC) will continue to be designated as having limited impact. This is because at this early stage, it is unclear whether the regional organizations would be modifying or terminating their RAS review process and/or terminology as this process will newly be conducted by the PC. For example, after the standard is approved, new Type 3 RASs added to the NPCC system would not necessarily be designated as being limited impact. This change in verbiage will also minimize the need for RAS-entities to classify RAS into the three categories below:

	1) Limited impact as per NERC; 2) Non-limited impact as per NERC; 3) NPCC Type 3 but non-limited impact as per NERC. ***"A RAS that was reviewed previously to the effective date of this standard, or after the effective date of this standard, by a regional process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact for the purposes of Requirement 4, Parts 4.1.3 and 4.1.3."***
Response:	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Selected Answer:	No
Answer Comment:	Limited impact RAS appears to be exempt from R4.1.3 and R4.1.4. The Rationale box for R4 defines the performance required for a "limited impact" RAS, and then R4.1.3 and R1.4.4 define the performance required for RAS except "limited impact" RAS. BPA believes the performance for all RAS should be the same. Limited impact RAS should

not be singled out to be exempt from meeting the performance requirements; it is really a matter of whether or not redundancy is required to be able to meet the required performance.

Although BPA agrees that for a “limited impact” RAS the level of review can be lower, we believe a “limited impact” RAS should still be designed such that failure or inadvertent operation of the RAS does not have an adverse impact on an adjacent TP or PC beyond the criteria the system is planned for.

BPA’s comments also apply to Attachment 2.

Response:

Ben Engelby - ACES Power Marketing - 6

Group Name: ACES Standards Collaborators - PRC-012-2 Project

Group Member Name	Entity	Region	Segments
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1

Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Ryan Strom	Buckeye Power, Inc.	RFC	4
Matt Caves	Western Farmers Electric Cooperative	SPP	1,5
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc. and Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Kevin Lyons	Central Iowa Power Cooperative	MRO	1
Mike Brytowski	Great River Energy	MRO	1,3,5,6

Selected Answer: No

Answer Comment: (1) The SDT needs to provide more details for “limited impact.” This is a vague term that needs to be clarified, as “cause or contribute to BES Cascading” could be interpreted in multiple ways. Any system that fails to operate as designed could be a contributing cause to an outage. How does an entity prove that a RAS does not cause cascading? It may be impossible to prove that a RAS has limited impact.

(2) Why does the SDT give the RC the independent authority without any specific criteria or guidelines to determine if the RAS has a limited impact? There should be an objective set of criteria for the RC to make a decision. We suggest adding detailed parameters or specific examples to show how a RAS may have a limited impact. One suggestion is a local area scheme that does not impact a larger area. The SDT could also leverage SPP, WECC or NPCC parameters for determining limited impact that should lead to the SDT to develop continent-wide criteria for determining limited impact RAS.

(3) Why does the SDT include "limited impact" RAS as being applicable to the standard? If it has a limited impact, then it should not apply at all. This proposal by the SDT is contrary to the past two years of NERC's RAI and RBR initiatives focusing on HIGH RISK activities. By definition, "limited impact" should not matter for BES reliability. The limited impact designation creates unnecessary compliance burdens without a clear benefit to increased reliability of the grid.

Response:

Phil Hart - Associated Electric Cooperative, Inc. - 1

Group Name:	AECI

Group Member Name	Entity	Region	Segments
Mark Ramsey	N.W. Electric Power Cooperative, Inc.	SERC	1
John Stickley	N.W. Electric Power Cooperative, Inc.	SERC	3
Kevin White	Northeast Missouri Electric Power Cooperative	SERC	1
Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	SERC	3
Michael B Bax	Central Electric Power Cooperative	SERC	1
Adam M Weber	Central Electric Power Cooperative	SERC	3
Denise Stevens	Sho-Me Power Electric Cooperative	SERC	1
Jeff L Neas	Sho-Me Power Electric Cooperative	SERC	3
Walter Kenyon	KAMO Electric Cooperative	SERC	1
Theodore J Hilmes	KAMO Electric Cooperative	SERC	3
Phillip B Hart	Associated Electric Cooperative Inc.	SERC	1
Todd Bennett	Associated Electric Cooperative Inc.	SERC	3
Matt Pacobit	Associated Electric Cooperative Inc.	SERC	5

Brian Ackermann	Associated Electric Cooperative Inc.	SERC	6

Selected Answer: Yes

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Selected Answer: Yes

Answer Comment: ERCOT supports the comments submitted by the IRC SRC and provides these additional comments.

ERCOT agrees with the SDT that a "limited impact" designation should be available. However, ERCOT no longer uses the RAS designations "Type 1" or "Type 2," and references to "ERCOT Type 2" in the footnotes and rationale boxes of this draft standard should be removed. The now defunct ERCOT "Type 2" designation was used to identify limited impact RAS.

Today, there are existing RAS in ERCOT that, although they are no longer designated "Type 2" still qualify as "limited impact." ERCOT requests clarification as to any particular process that would be required to designate an existing RAS as "limited impact."

Response:

Jared Shakespeare - Peak Reliability - 1

Selected Answer: Yes

Answer Comment: There are 4 WECC LAPS that exist which could, given failure to operate, contribute to cascading or voltage instability/collapse. Peak will work with WECC during the implementation phase to update these designations.

Response:

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2

Selected Answer: Yes

2. ***Implementation Plan for PRC-012-2: The drafting team revised the Implementation Plan to provide clarity and to lengthen the implementation period to thirty-six months to provide the responsible entities adequate time to establish the new working frameworks among functional entities. Do you agree with the revised Implementation Plan? If no, please provide the basis for your disagreement and an alternate proposal.***

Implementation Plan for PRC-012-2

Because some functional entities will need to establish new frameworks, which for Reliability Coordinators could include the hiring and training of personnel to perform and comply with the requirements of Reliability Standard PRC-012-2, the drafting team asserts that the 36 month implementation period is reasonable and appropriate.

The Implementation Plan includes a provision for limited impact RAS which states: "A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type 3 in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 and is subject to all applicable requirements. This provision was included because the drafting team modeled the limited impact designation after those two regional classifications.

For all other RAS implemented prior to the effective date of PRC-012-2 for which a limited impact designation is desired, the RAS-entity must submit the appropriate Attachment 1 information and request the RC review the RAS for designation as limited impact. There is nothing that precludes a RAS-entity from preparing an Attachment 1 submission and working with the RC prior to the effective date of PRC-012-2, in anticipation of the standard becoming enforceable. However, even if the reviewing RC determines the RAS qualifies as limited impact, the designation is not relevant until the standard becomes effective. Until then, the existing regional processes remain in effect as well as the existing RAS classifications or lack thereof.

The Implementation Plan also includes provisions that describe the initial performance of obligations under Requirements R4, R8, and R9. These clarifying provisions were inserted based on comments from the previous posting. The aforementioned requirements require initial actions that may be different based on the circumstances (for Requirement R4 - whether the RAS is existing, new, or functionally modified, for Requirement R8 - whether or not the RAS is limited impact, for Requirement R9 - whether or not an RC has an existing RAS database). The Requirement R4 language was updated to reflect the change in the requirement from sixty (60) full calendar months to five (5) full calendar years. The Requirement R8 language was modified for additional clarity. The Requirement R9 language was updated to clarify that a Reliability Coordinator that does not have a RAS database must establish its database by the effective date of PRC-012-2; i.e. during the thirty-six (36) month implementation period. By implication, the second provision states that all RCs are to perform the obligation of Requirement R9 within twelve full calendar months after the effective date of PRC-012-2.

John Fontenot - Bryan Texas Utilities - 1

Selected Answer: Yes

John Falsey - Invenergy LLC - 3 - FRCC,MRO,WECC,TRE,NPCC,SERC,SPP,RFC

Selected Answer: Yes

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Thomas Foltz - AEP - 5 -

Selected Answer:	Yes

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Selected Answer:	No
Answer Comment:	As written, the implementation plan creates confusion by singling out the 3 exceptions. SRP recommends identifying the requirements applicable with the 36 month timeframe. Additionally, as written, there is not established effective date for R9 where a database does not exist.
Response:	

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6

Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5
Amy Casucelli	Xcel Energy	MRO	1,3,5,6

Selected Answer: Yes

Terry BIlke - Midcontinent ISO, Inc. - 2

Selected Answer: Yes

Randi Heise - Dominion - Dominion Resources, Inc. - 5

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: Yes

Amy Casuscelli - Amy Casuscelli On Behalf of: Peter Colussy, Xcel Energy, Inc. , 6

Selected Answer: No

Answer Comment:	While Xcel Energy agrees with the clarifications in the Implementation Plan, we do not believe that BES reliability is well served by substantially increasing the revised standard's effective date from 12 to 36 months. Recognizing that 12-18 months is typically the minimum time taken by a NERC Standard to progress from industry approval to receiving FERC approval, a 36 months adder would effectively push the standard's effective date to 4 -5 years after industry approval – which we believe is an inordinately long and unnecessary delay to realize the BES reliability benefits promised by the proposed results-based standard. It is hard to conceive why the responsible entities would need 4-5 years "to establish the new working frameworks among functional entities" given that the only substantial process change in the proposed standard is due to the Reliability Coordinator serving as the RAS review/approval entity – and the associated new working framework is needed to support only R2 (and perhaps R3 to some extent), which constitutes a small proportion of the standard. Therefore, from our perspective, majority of the requirements are the functional responsibility of a single applicable entity and do not require establishing "new working frameworks among functional entities". Consequently, the previous 12 months implementation period is reasonably adequate – particularly because all existing RAS would retain status quo for several years beyond the standard's effective date due to the: (a) provision of limited impact RAS, and (b) grandfathering of all existing approved RAS until a functional modification occurs. We recommend reducing the implementation period back to 12 months to realize enhanced BES reliability in a more timely manner with the new results-based standard.

Response:

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Laura Nelson - IDACORP - Idaho Power Company - 1

Selected Answer: Yes

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Selected Answer: Yes

Answer Comment: PSEG strongly supports the 36-month implementation period as fair and reasonable.

Response:

Likes: 5

PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
Long Island Power Authority, 1, Ganley Robert
PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes:

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2	
Selected Answer:	Yes
Daniel Mason - City and County of San Francisco - 5	
Selected Answer:	Yes
William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2	
Selected Answer:	No
Answer Comment:	The SDT should accommodate the designation of "limited impact" RAS during the implementation period of PRC-012-2. As stated in our

	comments to Question 1 above, there needs to be a process in place to allow the RC and RAS entity to do this.
Response:	

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1	
Selected Answer:	Yes

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Selected Answer:	Yes

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC	

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Yes

Andrew Pusztai - American Transmission Company, LLC - 1

Selected Answer: Yes

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Selected Answer: No

Answer Comment: The SDT should accommodate the designation of “limited impact” RAS during the implementation period of PRC-012-2. As stated above, there needs to be a process in place to allow the RC and RAS entity to do this.

There should be an explicit statement in the implementation plan that the obligation for RC approvals apply only to those new and modified RAS after the effective date of the standard, not to those that had been previously reviewed by the RROs under the existing standard.

Response:

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Selected Answer: Yes

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1

Selected Answer: Yes

Steve Wenke - Avista - Avista Corporation - 5

Selected Answer: Yes

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: Yes

Mark Kenny - Eversource Energy - 3

Selected Answer: Yes

Chris Gowder - Chris Gowder On Behalf of: Tom Reedy, Florida Municipal Power Pool, 6

Answer Comment: FMPA believes 36 months is too long, and would suggest a timeframe between 12 and 36 months.

Response:

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC

Group Name: LG&E and KU Energy, LLC

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E adn KU energy, LLC	SERC	1,3,5,6
justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6
Chjarlie Freibert	LG&E and KU Energy, LLC	SERC	3
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Dan Wilson	LG&E and KU Energy, LLC	SERC	5

Selected Answer: Yes

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Name: RSC no Con Edison, Hydro Quebec

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1

Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
David Burke	Orange and Rockland Utilities	NPCC	3
Wayne Sipperly	New York Power Authority	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7

Kathleen M. Goodman	ISO-New England	NPCC	2
Helen Lainis	Independent Electricity System Operator	NPCC	2
Michael Jones	National Grid	NPCC	3
Silvia Parada Mitchell	NextEra Energy	NPCC	4
Connie Lowe	Dominion	NPCC	4

Selected Answer: Yes

Answer Comment:

Revise in R8 “Requirement R8 must be completed at least once within six (6) full calendar years of the effective date for PRC-012-2,” to “Requirement R8 must be completed at least once within six (6) full calendar years AFTER the effective date for PRC-012-2”. The reason for this is that the word “of” can imply “prior to the effective date” whereas “after” is clearly stating there is no requirement to present evidence prior to the effective date. If the SDT agrees then R4 should be modified as well.

Revise R9 to:

For each Reliability Coordinator that does not have a RAS database upon the effective date of PRC-012-2, as described above, the initial obligation under Requirement R9 is to establish a database on the effective date of PRC-012-2 as describe above. Each RC will perform the obligation of R9 within twelve full calendar months after the effective date of PRC-012-2 as describe above.

Response:

Erika Doot - U.S. Bureau of Reclamation - 5

Selected Answer: Yes

Rich Hydzik - Rich Hydzik On Behalf of: Bryan Cox, Avista - Avista Corporation, 5, 3, 1
Scott Kinney, Avista - Avista Corporation, 5, 3, 1

Selected Answer: Yes

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Selected Answer:	No
Answer Comment:	Texas RE recommends reducing the implementation period. This is a series of processes that already exist in some form or fashion and should not require a new construct that would take three years. In Requirement R9, the SDT indicates requirements follow "industry practice" which is a twelve month periodicity. Does the SDT contend that there are RASes in place that an RC or PC does not know about? Texas RE recommends that the SDT *eliminate the proposed implementation period or at least shorten the proposed three-year implementation period for PRC-12-2 to six months*. Alternatively, the SDT should link the 60-full-calendar month compliance window in PRC-12-2, R4 and the six- and twelve-year compliance periods in PRC-12-2, R8 to the effective date of PRC-12-2 and not the extended date (if any) set forth in the proposed implementation plan. The proposed PRC-12-2 establishes a process for reviewing new, functionally modified, or retiring RAS. As the SDT has recognized, failing to implement such a RAS review process could result in a significant gap in reliability. Specifically, the SDT stated in the rationale for Requirement R1 that RAS "action(s) can have a *significant impact on the reliability and integrity of the Bulk Electric System (BES)*." Given the importance of the RAS review scheme for reliability, Texas RE believes that three years is too long to implement the process contemplated in the proposed PRC-12-2. Texas RE also believes that the nature of the review process itself also

counsels in favor of a shorter review period. For example, PRC-12-2, R1 – R3 establishes the basic framework for RAS review. These requirements mandate that RAS-entities provide certain information regarding RAS to their respective Reliability Coordinators (RC), a minimum four-month period for the RC to review this information, and then a subsequent obligation for the RAS-entity to resolve any reliability issues identified by the RC prior to installing, functionally modifying, or retiring a particular RAS. Accordingly, these requirements do not contemplate immediate changes to existing physical assets, significant internal process transformations, or other issues that could potentially justify a three-year implementation period. Rather, they largely focus solely on the exchange and review of documentation, such as one-line drawings, for each RAS that is likely already be in the RAS-entity's possession today. RAS-entities and their associated RCs should therefore be able to begin the RAS review process with only minimal lead time following the adoption of PRC-12-2. Texas RE would further note that although RCs may need additional compliance resources to perform the RAS reviews contemplated under PRC-12-2, the existing language in PRC-12-2, R2 already provides RCs and RAS-entities with the flexibility to extend the review period if necessary based on a "mutually agreed upon schedule."

A similar rationale applies to the misoperation review and correction process in PRC-12-2, R5. As the SDT notes, "[t]he correct operation of a RAS is important for maintaining the reliability and integrity of the BES. *Any incorrect operation of a RAS indicates that the RAS effectiveness and/or coordination has been compromised.*" Texas RE agrees with this statement. In light of this fact, however, Texas RE believes that RAS-entities should begin RAS operational performance assessments following a RAS failure or misoperation immediately upon adoption of PRC-12-2 in order to avoid a significant reliability gap.

If the SDT elects to retain an implementation period of any length, Texas RE recommends that such implementation plan not apply to PRC-12-2, R4 and R8. These requirements already have significant time periods for RAS-entities to complete their compliance obligations embedded within them. For example, RAS-entities have six years under PRC-12-2, R8 to complete initial functional tests of their RAS (and 12 years for limited impact RAS if that definition is retained). Given that PRC-12-2, R4 and R8 already provide extended compliance horizons, Texas RE does not believe that additional time is necessary to implement these requirements. Instead, the 6-full-calendar month period in PRC-12-2, R4 and the six- and twelve-year periods in PRC-12-2, R8 should begin on the effective date of PRC-12-2 itself.

Additionally, the Implementation Plan contains the same “limited impact” language Texas RE has concerns about (see response to question 1).

Response:

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Selected Answer: Yes

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC **Selected Answer:** Yes
Eric Olson - Transmission Agency of Northern California - 1 **Selected Answer:** Yes
Mark Wilson - Independent Electricity System Operator - 2 - NPCC **Selected Answer:** Yes

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3
Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer: Yes

Answer Comment: Hydro One Networks Inc. would like to point out that Requirement R9 on Page 4/5 of the Implementation Plan does not stipulate a time fame by which an RC that does not have a RAS database is required to populate one by.

Response:

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Ben Engelby - ACES Power Marketing - 6

Group Name: ACES Standards Collaborators - PRC-012-2 Project

Group Member Name	Entity	Region	Segments
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Ryan Strom	Buckeye Power, Inc.	RFC	4
Matt Caves	Western Farmers Electric Cooperative	SPP	1,5
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc. and Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Kevin Lyons	Central Iowa Power Cooperative	MRO	1
Mike Brytowski	Great River Energy	MRO	1,3,5,6

Selected Answer: Yes

Answer Comment: We agree with the SDT that the implementation plan is appropriate.

Response:

Phil Hart - Associated Electric Cooperative, Inc. - 1

Group Name: AECI

Group Member Name	Entity	Region	Segments
Mark Ramsey	N.W. Electric Power Cooperative, Inc.	SERC	1
John Stickley	N.W. Electric Power Cooperative, Inc.	SERC	3
Kevin White	Northeast Missouri Electric Power Cooperative	SERC	1
Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	SERC	3
Michael B Bax	Central Electric Power Cooperative	SERC	1

Adam M Weber	Central Electric Power Cooperative	SERC	3
Denise Stevens	Sho-Me Power Electric Cooperative	SERC	1
Jeff L Neas	Sho-Me Power Electric Cooperative	SERC	3
Walter Kenyon	KAMO Electric Cooperative	SERC	1
Theodore J Hilmes	KAMO Electric Cooperative	SERC	3
Phillip B Hart	Associated Electric Cooperative Inc.	SERC	1
Todd Bennett	Associated Electric Cooperative Inc.	SERC	3
Matt Pacobit	Associated Electric Cooperative Inc.	SERC	5
Brian Ackermann	Associated Electric Cooperative Inc.	SERC	6

Selected Answer: Yes

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Selected Answer: No

Answer Comment:	ERCOT supports the comments submitted by the IRC SRC and provides these additional comments. The SDT should consider whether the standard should be clarified to address the designation of “limited impact” RAS during the implementation period of PRC-012-2.
Response:	

Jared Shakespeare - Peak Reliability - 1

Selected Answer:	No
Answer Comment:	Peak will see significant additional workload burden with this standard implementation and can plan to be ready within 18 months.
Response:	

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2

Selected Answer: Yes

3. ***Revised Definition of SPS and its Implementation Plan: The drafting team revised the definition of Special Protection System to cross-reference the revised definition of Remedial Action Scheme. The Implementation Plan for the revised definition of Special Protection System aligns with the effective date of the revised definition of Remedial Action Scheme. Do you agree with the proposed definition and its implementation plan? If no, please provide the basis for your disagreement and an alternate proposal.***

Revised Definition of SPS and its Implementation Plan

On February 3, 2015, NERC submitted a petition to the Commission requesting approval of the revised definition of "Remedial Action Scheme." Along with the revised definition, NERC submitted Reliability Standards that had been revised by replacing the term "Special Protection System" with the newly revised "Remedial Action Scheme." On November 19, 2015, the Commission issued a Final Order approving the RAS definition and associated standards. For a variety of reasons, NERC was unable to revise every Reliability Standard that contains the term Special Protection System or its acronym SPS prior to that FERC filing. The term is also used in various NERC, Regional Entity, and registered entity documents. Moving forward, NERC will systematically remove the term Special Protection System and its acronym SPS from Reliability Standards during the enhanced periodic review process, and replace the term in NERC documents as they are revised. The drafting team encourages the Regional Entities and registered entities to expeditiously revise their documentation as well. Until the term Special Protection System can be completely erased from NERC Reliability Standards, it is necessary to retain it in the NERC "Glossary" and cross-reference it to the term Remedial Action Scheme to ensure consistency of meaning regardless of which term is used. The Implementation Plan for the revised definition of Special Protection System aligns with the effective date of the revised definition of Remedial Action Scheme.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

John Falsey - Invenergy LLC - 3 - FRCC,MRO,WECC,TRE,NPCC,SERC,SPP,RFC **Selected Answer:** Yes
Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1 **Selected Answer:** Yes
Thomas Foltz - AEP - 5 - **Selected Answer:** Yes
Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5

Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5
Amy Casucelli	Xcel Energy	MRO	1,3,5,6

Selected Answer: Yes

Terry BIlke - Midcontinent ISO, Inc. - 2

Selected Answer: Yes

Answer Comment: While it’s inferred from the standard, there should be an explicit statement in the implementation plan that existing SPS implemented under the RRO standard do not need to be re-approved by the RC.

Response:

Randi Heise - Dominion - Dominion Resources, Inc. - 5

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6

Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: Yes

Amy Casuscelli - Amy Casuscelli On Behalf of: Peter Colussy, Xcel Energy, Inc. , 6

Selected Answer: Yes

Answer Comment: We will appreciate if the Implementation Plan can also address the target date for retirement/elimination of the term/acronym SPS from the NERC Glossary and Standards. Wasn't eliminating the usage of SPS one of the primary drivers for recommending Remedial Action Scheme (RAS) as the preferred term when the RAS/SPS definition was revised?

Response:

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Laura Nelson - IDACORP - Idaho Power Company - 1

Selected Answer: Yes

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3

Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Selected Answer: Yes

Answer Comment: In the future, NERC's Reliability Standards Development Plan should have the goal of eliminating "Special Protection System" or "SPS" from standards when those standards are revised.

Response:

Likes: 5

PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
Long Island Power Authority, 1, Ganley Robert
PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2 **Selected Answer:** Yes
William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2 **Selected Answer:** Yes
Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1 **Selected Answer:** Yes
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1

Selected Answer: Yes

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Yes

Andrew Pusztai - American Transmission Company, LLC - 1

Selected Answer: Yes

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Selected Answer: Yes

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Selected Answer: Yes

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1

Selected Answer:	Yes

Steve Wenke - Avista - Avista Corporation - 5

Selected Answer:	Yes

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:	Yes

Mark Kenny - Eversource Energy - 3

Selected Answer: Yes

Chris Gowder - Chris Gowder On Behalf of: Tom Reedy, Florida Municipal Power Pool, 6

Selected Answer: Yes

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC

Group Name: LG&E and KU Energy, LLC

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E adn KU energy, LLC	SERC	1,3,5,6
justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6
Chjarlie Freibert	LG&E and KU Energy, LLC	SERC	3
Linn Oelker	LG&E and KU Energy, LLC	SERC	6

Dan Wilson	LG&E and KU Energy, LLC	SERC	5

Selected Answer: Yes

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Name: RSC no Con Edison, Hydro Quebec

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1

Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
David Burke	Orange and Rockland Utilities	NPCC	3
Wayne Sipperly	New York Power Authority	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7
Kathleen M. Goodman	ISO-New England	NPCC	2
Helen Lainis	Independent Electricity System Operator	NPCC	2
Michael Jones	National Grid	NPCC	3
Silvia Parada Mitchell	NextEra Energy	NPCC	4
Connie Lowe	Dominion	NPCC	4

Selected Answer: Yes

Erika Doot - U.S. Bureau of Reclamation - 5

Selected Answer: Yes

Rich Hydzik - Rich Hydzik On Behalf of: Bryan Cox, Avista - Avista Corporation, 5, 3, 1
Scott Kinney, Avista - Avista Corporation, 5, 3, 1

Selected Answer: Yes

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Selected Answer: Yes

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Selected Answer: Yes

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Eric Olson - Transmission Agency of Northern California - 1

Selected Answer: Yes

Mark Wilson - Independent Electricity System Operator - 2 - NPCC

Selected Answer: Yes

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3 Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer: Yes

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Ben Engelby - ACES Power Marketing - 6

Group Name: ACES Standards Collaborators - PRC-012-2 Project

Group Member Name	Entity	Region	Segments
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Ryan Strom	Buckeye Power, Inc.	RFC	4
Matt Caves	Western Farmers Electric Cooperative	SPP	1,5
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc. and Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Kevin Lyons	Central Iowa Power Cooperative	MRO	1
Mike Brytowski	Great River Energy	MRO	1,3,5,6

Selected Answer: No

Answer Comment: The SDT should eliminate the SPS definition in its entirety. An archived definition could also reference the current definition by stating “see Remedial Action Scheme.” There is no reason to keep SPS as an active glossary term. This will only cause more confusion in the industry.

Response:

Phil Hart - Associated Electric Cooperative, Inc. - 1

Group Name: AECI

Group Member Name	Entity	Region	Segments
Mark Ramsey	N.W. Electric Power Cooperative, Inc.	SERC	1
John Stickley	N.W. Electric Power Cooperative, Inc.	SERC	3
Kevin White	Northeast Missouri Electric Power Cooperative	SERC	1
Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	SERC	3
Michael B Bax	Central Electric Power Cooperative	SERC	1

Adam M Weber	Central Electric Power Cooperative	SERC	3
Denise Stevens	Sho-Me Power Electric Cooperative	SERC	1
Jeff L Neas	Sho-Me Power Electric Cooperative	SERC	3
Walter Kenyon	KAMO Electric Cooperative	SERC	1
Theodore J Hilmes	KAMO Electric Cooperative	SERC	3
Phillip B Hart	Associated Electric Cooperative Inc.	SERC	1
Todd Bennett	Associated Electric Cooperative Inc.	SERC	3
Matt Pacobit	Associated Electric Cooperative Inc.	SERC	5
Brian Ackermann	Associated Electric Cooperative Inc.	SERC	6

Selected Answer: Yes

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Selected Answer: Yes

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2

Selected Answer: Yes

4. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

Stakeholders commented on a variety of topics and asked for clarity in some areas. The drafting team made numerous additions to the rationales and Supplemental Material in the draft standard to address the clarity concerns. The information contained in the rationale boxes is appended to the end of the standard after approval and as such remains part of the standard for perpetuity.

The drafting team's position on the various topics are stated below. For comments concerning the limited impact designation or the implementation plan, please reference questions 1 and 2 above.

General

The drafting team is charged with assigning the requirements of the new standard to the specific users, owners, and operators of the Bulk-Power System while incorporating the reliability objectives of all the RAS-related standards. In drafting this standard, the team has worked diligently to minimize the changes that will be required from the existing processes.

Each requirement of the standard has a reliability objective. It is the intent of the drafting team to be as non-prescriptive as possible to allow entities latitude in developing procedures and practices to satisfy the "how" of those requirements. The standard provides a skeletal system on which the applicable entities can build and codify their processes.

RAS Review

Because each Remedial Action Scheme (RAS) is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES), the drafting team maintains a review of each proposed new RAS, or each existing RAS proposed for functional modification or retirement should be performed. The owner(s) of the RAS are responsible for the comprehensive design and detailed implementation of the RAS. The drafting team uses the term RAS-entity and defines it in the Applicability of PRC-012-2 as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. Because the RAS-entity is the party that designs and implements its RAS, the drafting team maintains an independent review of the RAS, as is currently performed by technical groups from the Regions, is necessary. To promote a comprehensive review of the RAS, the RAS-entity must provide the reviewer information (Attachment 1) that details the RAS design, function, and operation.

Reliability Coordinator

The drafting team maintains that the Reliability Coordinator (RC) that coordinates the area where the RAS is located 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. The Wide Area purview 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, Planning Coordinator, Transmission Planner, or other entities 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 drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November, 2009.

The RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the review if the RC believes it will enhance the quality and efficiency of the review process; however, the RC will retain the responsibility for compliance. The drafting team maintains that RCs have options for accomplishing their review responsibilities -some RCs may choose to hire additional staff while others may enter into business arrangements with third parties. The drafting team included a thirty-six (36) month implementation period for PRC-012-2 to provide sufficient time for the RCs and other applicable entities to develop the framework of their choosing.

Planning Coordinator

In RAS-review: The Planning Coordinator (PC) or Transmission Planner (TP) is the entity that performs the planning studies and most often identifies the need for a RAS and/or determines the necessary RAS characteristics. These studies are included in the Attachment 1 information supplied by the RAS-entity to the Reliability Coordinator (RC) for RAS review and approval. Because the

PC is involved in developing the studies and/or evaluations, the drafting team did not include them as mandatory participants in the RAS review and approval process where they would be responsible for judging and approving their own work.

In Requirement R4: Because they have a wide area planning perspective, the PC is the best-suited functional entity to perform the periodic RAS evaluation 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, similar to the planning analyses performed by PCs. To promote reliability, the PC is required to provide the results of the evaluation to each impacted TP and PC, in addition to each reviewing RC and RAS-entity. In cases where a RAS crosses PC boundaries, each affected PC is responsible for conducting either individual evaluations or participating in a coordinated evaluation.

RAS-entity

The term RAS-entity is defined in the Applicability as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If all of the RAS (RAS components) has a single owner, then that RAS-entity has sole responsibility for all the activities assigned within the standard to the RAS-entity.

The standard does not stipulate compliance methods. RAS-entities have the option of collaborating to fulfill their responsibilities for each applicable requirement. Such collaboration and coordination should promote efficiency in achieving the reliability objectives of the requirements; however, the individual RAS-entity must be able to demonstrate its participation for compliance. As an example, the individual RAS-entities could collaborate to produce and submit a single, coordinated Attachment 1 (acknowledging all RAS-entities that participated in the provision of data) to the reviewing RC pursuant to Requirement R1 to initiate the RAS review process.

Participate (used in Requirements R5, R6, R8)

The drafting team is charged with assigning the requirements of the new standard to the specific users, owners, and operators of the Bulk-Power System while incorporating the reliability objectives of all the RAS-related standards. In drafting this standard, the drafting team has worked diligently to minimize the changes that will be required from the existing processes. The drafting team recognizes that RAS with multiple owners inherently require coordination among all the participating RAS-entities from the first conceptual design through construction to operations, testing, maintenance and retirement.

For purposes of PRC-012-2, when a RAS has more than one owner, each RAS-entity is obligated to participate in the various activities identified by the requirements to the extent of its ownership. Collaboration, coordination, and communication between and among entities regarding RAS issues helps to ensure efforts are not duplicated and best serves reliability by promoting awareness. For purposes of creating efficiencies, the drafting team maintains registered entities that currently share ownership of a RAS (RAS-entities) are in some manner already communicating, sharing information, and coordinating RAS tasks such as operations analysis, Corrective Action Plan (CAP) development, and functional testing. The drafting team is confident that entities will continue to do this after this standard is effective and that entities will communicate with each other if there is any question or doubt of responsibility surrounding any requirement.

From the NERC Drafting Team Reference Manual, Version 2, January 2014, Attachment A — Verbs Used in Reliability Standards: "When developing a new or revised standard, DTs should try to use terms that have already been defined or terms that are already used in other Reliability Standards to achieve a high degree of consistency between standards. To that end, the Standards staff, working with key DT members, put together the following list of verbs and their associated definitions. These verbs are all used in requirements in existing Reliability Standards. This verb list and its definitions are not in the Glossary of Terms used in NERC Reliability Standards but these verbs and their definitions should serve as a reference for DTs who are trying to minimize the introduction of new terms into Reliability Standards. Participate is defined as "To take part or share in something."

Requirement R8 – functional testing

The reliability objective of Requirement R8 is to maintain the non-Protection System components of a RAS; i.e., the controllers (programmable logic controllers (PLCs), personal computers (PCs), multi-function programmable relays, remote terminal units (RTUs), and logic processors), and to verify the overall performance of the RAS through functional testing. Functional tests validate RAS operation by ensuring System states are detected and processed, and that actions taken by the controls are correct and occur within the expected time using the in-service settings and logic (functional testing by default operates the processing logic and infrastructure of a RAS). Functional testing should not be confused with the component focused maintenance of PRC-005 Protection System Maintenance. PRC-005 is not applicable to non-Protection System components such as RAS controllers.

RAS designated as limited impact have functional testing intervals of up to twelve full calendar years. However, all other RAS have up to six full calendar year intervals because of the higher risk they pose to negatively impact BES reliability should they operate incorrectly or fail to operate. The drafting team recognizes that PRC-005 extends the maintenance interval for monitored multi-function programmable relays to twelve calendar years; however, the drafting team asserts that the inadvertent operation or failure of a RAS subject to the six year functional test interval poses too much risk to the reliability of the BES to extend the test interval beyond six years.

John Fontenot - Bryan Texas Utilities - 1

Answer Comment:	na

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5 - RFC

Answer Comment:	We maintain our previous position that the draft standard is entirely deficient due to the patchwork nature of responsibility for a RAS, especially when there are multiple Owners of portions of the RAS. The standard appears it would be effective where there is only one RAS entity. However, there is no mechanism for overall coordination and responsibility for the case when there are multiple owners. In this respect, the previous draft was superior in that it recognized there needs to be a single RAS Owner that has overall responsibility for ensuring the requirements of PRC-012-2 are met. There is no entity

designated to take the lead in developing the data needed for R1, including the technical studies needed to describe system performance. A weak acknowledgement of the need for collaboration among multiple entities is a statement in the R5 Rationale: “RAS-entities may need to collaborate with their associated Transmission Planner to comprehensively analyze RAS operational performance.” There is nothing in the Standard as written that will drive the needed “directed collaboration” to bring beneficial results in the analysis of RAS operations and any corrections needed.

Our recommendation is to restore the RAS-Owner entity (or RAS-Coordinator ?) and to identify this entity as the Transmission Owner and/or Transmission Planner having primary interest and technical capability to execute the technical studies (steady state, dynamic, etc), and designate these to have lead or primary responsibility for the Requirements. The individual RAS-entities with ownership of related equipment would be responsible to participate in the requirements as listed, under the umbrella of the primary entity.

Absent a Standard requiring a single entity to take charge of the development of RAS, analysis of its operations, and development of needed CAP’s, it appears unlikely that the Standard will actually produce meaningful results, nor an improvement in reliability. This despite the great amount of effort that will be required to ensure compliance.

Response:

Likes:	1	Associated Electric Cooperative, Inc., 1, Hart Phil
Dislikes:	0	

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Answer Comment:	In regards to R8 Oncor Electric Delivery does not differentiate between functional testing of a protection system and functional testing of a RAS. This is an unnecessary requirement, and any responsible entity will perform functional testing of a RAS when maintaining the protection system components of a RAS. Oncor recommends that an entity whose PRC-005-2 maintenance program covers functional testing of its RASs does not have to comply with PRC-012-2 R8. The non protection system components of a RAS are tested when performing maintenance under PRC-005. Hence adhering to the proposed R8 in PRC-012-2 will only require additional documentation while not positively affecting the reliability of the BES. In regards to R1 Oncor Electric Delivery believes the RAS information required in attachment 1 contains more than is necessary for a review and cannot always be obtained for every RAS. Also providing all this information is not required prior to placing a protection system under PRC-005 in service so it should also not be required under PRC-012-2.

Response:

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Answer Comment:

SRP appreciates the opportunity to comment on the proposed revisions to PRC-012 and provides the following additional comments related tot he draft posted.

1) Similar to concerns with “limited impact”, “functionally modified” as written is an unofficial defined term within the standard. SRP recommends defining the term “functionally modified” and including it within the NERC Glossary of Terms.

2) Attachment 1 and 2 as originally presented were checklists. As currently written, they are not. Rather they are itemized lists of information to be included or assessment to be made. As written the Attachments 1 & 2 create ambiguity in regards to what is expected from the submitter and reviewer.

3) Under R1, the identification within the rationale that “ideally, when there is more than one RAS- entity for a RAS…” is not captured within the language of the standard. SRP agrees with this intention, however recognizes that once the rationale is removed from the standard, this

will be lost. SRP recommends adjusting the language of the standard or including the language within the measure to more clearly indicate the intention of the SDT.

4) Under R3, the RAS entity that receives feedback is required to “resolve each issue to obtain approval”. This language as written does not specify a resubmittal of the information required under Attachment 1 and fails to reactivate the timeframe identified for the reviewer under R3. SRP recommends adjusting the language to “ resolve each issue and resubmit Attachment 1 information to the reviewing RC to obtain approval…”.

5) Under R4, there is an inconsistent use of quotes around “limited impact” again pointing to the previously discussed confusion created by imbedding an unofficially defined term within the standard.

6) R^ has a singular/ plural inconsistency "Pursuant to the Requirements R5, or..". This should be singular.

Similar to the issue identified under R1, R8 requires each entity to participate in “performing” the functional test. This would require all partial owners to be involved in the functional test of a RAS. Participation is vague and can result in confusion over what would constitute participation. SRP recommends adjusting the language to read “the RAS entity shall perform a functional test..”. This would allow joint owners to coordinate the activities

Response:

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2

Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5
Amy Casucelli	Xcel Energy	MRO	1,3,5,6

Answer Comment:

R4.1.3 and R4.1.4 – These requirements refer to 'single component malfunction' and 'single component failure' respectively. However, the standard does not contain any identification or clarification of which types of components must be included and which may be excluded in RAS evaluations. This deficiency could be addressed by including text in the Supplemental Material section under Requirement 4 that the drafting team developed for a response in its Consideration of Comments for Draft 1 of PRC-012-2.

- *"An exhaustive list of components is not practical given the variety that could be applied in RAS design and implementation. See Item 4a in the Implementation Section of Attachment 1 in the Supplemental Material section for typical RAS components for which redundancy may be considered. The RAS-entity should have a clear understanding of what components were applied to put a RAS into service and which were already present in the system before a RAS was installed. The RC* *will make the final determination regarding which components should be regarded as RAS components during its review"*.

R5 – This requirement does not obligate RAS-entities to provide their results of the operational performance analysis of a RAS event to impacted Transmission Planners and Planning Coordinators. However, this action should be proposed in the Supplemental Material section.

R6 – This requirement does not obligate RAS-entities to provide their Corrective Action Plans to impacted Transmission Planners and Planning Coordinators. However, this action should be proposed in the Supplemental Material section.

R8 - The purpose of Version 2 of PRC-005 was to consolidate all maintenance and testing of relays under one Standard. Having RAS testing within PRC-012-2 would be contrary to that end. The NSRF proposes to address this concern as follows:

• Functional testing of RAS (as stated in Requirement 8 of PRC-012-2) is a maintenance and testing activity that would be better included in the PRC-005 standard. The present PRC-005-2 Reliability Standard is the maintenance standard that replaces PRC-005-1, 008, 011 and 017 and was designed to cover the maintenance of SPSs/RASs. However, Reliability Standard PRC-005-2 lacks intervals and activities related to non-protective devices such as programmable logic controllers. The NSRF recommends that a requirement for maintenance and testing of non-protective RAS components be added to a revision of PRC-005-6, rather than be an outlying maintenance requirement located in the PRC-012-2 Standard.

	R8. Of the proposed Standard states: *Each RAS-entity shall participate in performing a functional* ***test*** *of each of its RAS to* ***verify*** *the overall RAS performance and the proper operation of non-Protection System components.* Please provide clarification that the word **test** and **verify** is aligned with the definitions contained in the Supplementary Reference and FAQ, PRC-005-2 Protection System Maintenance dated October 2012.
Response:	

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer Comment:	a. The Standard Drafting Team gave examples of “functional modifications” in the Rationale Box for R1. Seminole requests that these examples be moved into the Standard language to make these examples more than mere suggestions by the SDT, which would be the case if this language is left in the Application Guidelines. b. For Requirement R1, can the SDT confirm that each RAS-entity, even if the entity is only a partial ower of a RAS, must submit a fully completed Attachment 1 submission? c. For Requirement R3, if the RAS-entity disagrees with "issues" the RC indicates, can the RAS-entity document technical reasons why the RAS-

entity's design is satisfactory or does the RAS-entity have to get REC approval?

d. Footnote 1 for Requirement 4 appears to state that the only existing limited impact RAS are located in NPCC, ERCOT, and WECC. The footnote does not appear to allow for existing limited impact RAS in other Regions, specifically the FRCC. Seminole requests that the drafting team modify the language in the Standard and footnote to clarify that existing RAS in the FRCC and other Regions can also have existing limited impact RAS.

Response:

Randi Heise - Dominion - Dominion Resources, Inc. - 5

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6

Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Answer Comment:

Dominion believes that the term “in-kind” included in Footnote 4, “Changes to RAS hardware beyond in-kind replacement of existing components” is vague and suggests that the term be clarified such that the reader knows that the replacement of an electromechanical relay with a microprocessor relay is construed as an “in kind” replacement, as the drafting team noted in their December 15th presentation. The concept of “In-kind” replacement could be taken a step further. For example, a discrete ladder logic circuit that includes contacts, overcurrent and voltage relays could be replaced entirely inside the software logic of a multifunction device. From a black-box viewpoint, the old and new RAS would be identical in function. Dominion also suggests for additional consideration that the replacement of many discrete components with a single multifunction component also be considered an “in kind” replacement so long as for a given set of inputs the “black box” produces the same outputs as the previous RAS would. In the case of a breaker failure event, the Standards Drafting Team “SDT” indicates the need for RAS redundancy even though that would be a double failure event (failure of the RAS and failure of the breaker). Dominion suggests that it is sufficiently redundant to use the existing breaker failure relay (non-redundant) to initiate both RAS schemes. This can be accomplished by each RAS using a different contact off the breaker failure relay that was separately fused.

Dominion suggests the SDT consider using a consistent measure of time, either calendar months or full calendar days, for responding and reporting. For example, Requirement 2 states: Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1, shall, within **four- full- calendar months** of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity." Whereas Requirement 4 states that: "Each RAS entity, within **120- full calendar days** of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall:"

Response:

Amy Casuscelli - Amy Casuscelli On Behalf of: Peter Colussy, Xcel Energy, Inc. , 6

Answer Comment:

We agree with the footnote definition of "limited impact" RAS and the exceptions stated in parts 4.1.3 and 4.1.6 of R4.

Usage of both RAS-owner and RAS-entity in the previous posting of the draft standard was confusing – so we agree with the SDT's solution to eliminate one of them. We also agree that retaining the previous definition of RAS-owner as Applicable Entity is more appropriate. However, we do not understand what is the compelling need and/or the benefit of reassigning the RAS-owner definition to the RAS-entity. Absent a rationale by the SDT for preferring RAS-entity, we suggest using RAS-owner since it better aligns with the various owners comprised in the definition.

Response:

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Answer Comment:

Regarding the third bullet when describing Functional modifications; what does "in-kind" mean? The description in the Supplemental Material describes it but Tri-State believes the phrase "preserves the original functionality" is more appropriate. This is used in several places (Rationale for R1, Att. 1, and Att. 2, at a minimum).

Regarding the fourth bullet when describing Functional modifications; we suggest changing the language to read "...beyond correcting existing errors". The phrase "error correcting" has other implications and is not described in the Supplemental Material.

Tri-State would like to know what the SDT's intentions were when adding the statement "The RC is not expected to possess more information or ability than anticipated by their functional registration as designated by NERC" to the Rationale for Requirement R2. We don't know why that was necessary.

Response:

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Answer Comment:

1. Suppose a RAS is intended to cause a generator to run-back under a defined set of conditions. Further, suppose that the generator and the RAS-entity that sends run-back signals to the generator's DCS are different (non-affiliated) companies. Is the generator's DCS a part of the RAS?

2. R4.2 should be expanded with respect to the entities a Planning

Coordinator "provides the results of the RAS evaluation including any identified deficiencies." PSEG believes that the results should also be provided to non-RAS entities (i.e., TOs, GOs, and DPs) whose facilities are impacted by the operation of a RAS.

Attachment 1 and R1 should be modified as follows for the reasons provided:

3. In many cases, a single RAS has multiple RAS entities. Attachment 1 should be modified so that each RAS entity's components in the RAS are clearly identified.

4. The entity responsible for providing the information required in Attachment 1 Section II should be identified. For example, item II.6 and III.4 should be completed by the Planning Coordinator (who has the capability to provide that information) rather than the RAS entity. The comments that PSEG submitted for the initial draft addressed this concern and recommended that the RAS entity's Transmission Planner prepare this section; however, since the standard is applicable to "Planning Coordinator," that entity is more appropriate. In response to PSEG's comments, the SDT stated:

"The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval."

PSEG unequivocally agrees with this comment. Therefore, R1 should be modified to state that “each RAS entity and its Planning Coordinator shall provide the information required of it in Attachment 1 ….”

With this change, Attachment 1 should be modified to identify which entity (RAS entity or Planning Coordinator) is required to provide what information.

Other Attachment 1 items:

5. Items II.1 and II.2 are duplicative to I.4.e and I.4.f. Therefore, items I.4.e and I.4.f should be deleted. Also, Items II.1 (contingencies and System conditions) and II.2 (RAS action) should be stated so that each contingency and System condition is linked to an expected RAS action (assuming all RAS equipment operates properly). As a simplification, the two items could be combined in to one item: “Each contingency and System condition that the RAS is intended to remedy and the associated RAS response.”

6. Item III.1 should have include be expanded to say “and documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in-service or is being maintained.” This is required to ensure that non-RAS equipment that is essential to the successful operation of the RAS is not inadvertently removed from service.

Response:

Likes:	5	PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla PSEG - PSEG Fossil LLC, 5, Kucey Tim Long Island Power Authority, 1, Ganley Robert PSEG - Public Service Electric and Gas Co., 1, Smith Joseph PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
Dislikes:	0	

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Answer Comment:

Under Requirement R4.2 additional clarification regarding the as to the "reviewing Reliability Coordinator". We suggest changing the wording to the "impacted" Reliability Coordinator from "reviewing" as shown below.

4.2. Provide the results of the RAS evaluation including any identified deficiencies to

each impacted Reliability Coordinator and RAS-entity, and each impacted

Transmission Planner and Planning Coordinator.

Under R5, each RAS entity must review any RAS operation whether the operation was as designed or a there was an unintended or adverse BES response. Under R6, wording calls for a Corrective Action Plan (CAP) to be developed no matter what. We suggest clarifying wording under R6 as follows to limit development of a CAP to when RAS operation caused an unintended or adverse BES response.

R6. Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) when RAS operation caused an unintended or adverse BES response and submit the CAP to its impacted Reliability Coordinator(s) within six full calendar months…

Response:

Daniel Mason - City and County of San Francisco - 5

Answer Comment:

Hetch Hetchy does not agree with the proposed change in the definition of a RAS entity. HHWP believes that the definition of a RAS entity in the last posted version of PRC-012 should be retained and that the RAS owner designated to represent all RAS-owners should be responsible for ensuring information provided for evaluation of RAS impacts is available to the appropriate reliability entities .The proposed change in the definition of a RAS entitiy unnecessarily expands the scope of entities involved in RAS evaluation and is likely to lead to duplication of efforts, or reliabilty gaps. Having a single point of contact for RAS

	coordination/management is the efficient and effective approach for ensuring that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System.
Response:	

William Temple - William Temple On Behalf of: Mark Holman, PJM Interconnection, L.L.C., 2

Answer Comment:	The Rationale Box for Req. 1 contains important guidelines for when a review of RAS is needed. These should be captured and retained in a standing Guideline. Also, there should be a need to review a RAS when the settings that initiate the RAS are changed. In the Applicability section of Attachment 3, the three entities identified for obligations to PRC-012-2 are explained with a concluding caveat that these entities can collaborate to meet the requirements of the standard. “The standard does not stipulate particular compliance methods. RAS-entities have the option of collaborating to fulfill their responsibilities for each applicable requirement. Such collaboration and coordination may promote efficiency in achieving the reliability objectives of the requirements; however, the individual RAS-entity must be able to

demonstrate its participation for compliance. As an example, the individual RAS-entities could collaborate to produce and submit a single, coordinated Attachment 1 to the reviewing RC pursuant to Requirement R1 to initiate the RAS review material to the process."

We request how this allowance will be included in the RSAW for this standard?

With regards to Req. 4.2, we suggest that the Planning Coordinator only needs to provide evidence of the evaluation results to the RAS-entity if a deficiency is identified. This will help reduce the compliance burden of submitting documentation if the evaluation results are acceptable.

R6 should be clarified as proposed:

"Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of:"

Also, throughout the standard, references to days and months should be standardized. There are references to 60 calendar months, 6 calendar months, and 120 calendar days. These time periods should be expressed in either all months or all days to maintain consistency throughout the standard.

Response:

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Answer Comment:	There are multiple registered Planning Coordinators in GTC's Planning Area, although we joint plan, we would like to propose a simple solution to ensuring that each Planning Coordinator will become aware of any new or materially modified RAS within GTC's Planning Area. Additionally the following rationale is provided to make the basis for our recommendation: · Not every PC is registered as an RC. · There may be multiple PCs in 1 RC area · PCs that do not own transmission assets may not be aware of new or functionally modified RAS's proposed by others and shared only with the RC · A revision to R1 to include the Planning Coordinator as well is not an option, because some RAS entity's may not be aware of multiple PC registrations in their area. Therefore, GTC proposes the following new requirement to compliment the obligations of the Planning Coordinator under requirement R4. R10(proposed new requirement): Each Reliability Coordinator shall provide each Planning Coordinator in their Reliability Coordinator area a copy of the RAS database maintained in accordance with R9, at least

	once every twelve full calendar months. Additionally, GTC recommends a slight change to requirement R4 to compliment the new proposed R10 requirement R4. Each Planning Coordinator that receives a list of RAS's pursuant to R10, at least once every 60 full calendar months, shall:
Response:	

Jeri Freimuth - APS - Arizona Public Service Co. - 3

Answer Comment:	• To promote clarity and efficiency, AZPS suggests adding the following to the Rational for Requirement R4 "*"Ideally, for a RAS which is activated in multiple Planning Coordinator areas, a mutually agreed upon Planning Coordinator of one of the multiple Planning Coordinator areas shall perform the R4 evaluation."* • Page 6, foot note 1 defines the limited impact RAS as that which cannot "cause or contribute" to cascading etc. The word "contribute" should be removed because it reduces clarity to the standard. The term "contribute" is too broad and creates challenges to precisely evaluate. • Attachment 2 I. 6 states that a limited impact RAS is determined by

the RC. AZPS suggests modifying the language to "…limited impact RAS as determined by the RC or through a regional review process." This will add flexibility to the implementation of the standard and/or allow for an appeal process to be created, if needed.

Response:

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1

Answer Comment: On page 53 of the redlined version of the proposed standard, in the Technical Justifications for Attachment 1 Content Supporting Documentation for RAS Review section, II. 6., there does not appear to be mention of the limited impact exclusion.

Response:

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Answer Comment:

General Comment: Duke Energy suggests that the drafting team consider placing the definition of "Remedial Action Scheme" in the standard for the industry to reference while reviewing the proposal. The RAS definition is more complex than most other definitions found in the NERC Glossary and compliance is directly dependent on the proper application of the RAS definition to a particular circumstance. Therefore, any future changes to the definition should be held to the same review and approval process requirements as the RAS standard itself. This would best be accomplished by incorporating the definition as an integral part of the standard. Precedence for this approach already exists in other NERC standards. Without this approach, it is possible to effectively change the scope of the NERC standard without due process.

After further discussion, we have concerns regarding the RC being accountable for the Remedial Action Scheme (RAS) review from a compliance perspective. The RC is not able to or is not in the position to facilitate a review for technical correctness of an RAS, and will be dependent upon a Planning Coordinator/RAS-entity to provide this information. On page 2 of the Question and Answer document supplied by the drafting team on the project, it is stated;

"The RC is not expected to possess more information or ability than anticipated by their functional registration as designated by NERC."

We agree with this sentiment that an entity should not be held accountable for a product that it is not able to or can readily provide. However, further down in the same paragraph, the Q & A document reads;

"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."

The drafting team admits that the RC will need assistance from other entities to perform or provide input for the RAS review. However, the RC will be held accountable for the accuracy and technical input that goes into said review. Requiring an entity to be accountable for information that it may not be able to verify itself is problematic, and should be revisited. We recommend that the drafting team consider adding language in the standard stating that the RC will not be held responsible for the accuracy or content of the technical analysis that is done by the Planning Coordinator/RAS-entity. Rather, the RC is responsible for ensuring that an adequate review is conducted, whether it is an individual review or coordinated review, merely for "identifying reliability-related considerations relevant to various aspects of RAS design and implementation", as stated in the Technical Justification for

	Attachment 2 Content. This is a task that the RC would be able to evaluate and verify itself without relying on the work of another entity to achieve its compliance.
Response:	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer Comment:	ATC has several recommendations for improvement or clarification on the draft Standard, for consideration by the SDT as listed below: · R4.1.3 and R4.1.4 – These requirements refer to 'single component malfunction' and 'single component failure' respectively. However, the standard does not contain any identification or clarification of which types of components must be included and which may be excluded in RAS evaluations. This deficiency could be addressed by including text in the Supplemental Material section under Requirement 4 that the drafting team developed for a response in its Consideration of Comments for Draft 1 of PRC-012-2. *"An exhaustive list of components is not practical given the variety that could be applied in RAS design and implementation. See Item 4a in the Implementation Section of Attachment 1 in the Supplemental Material section for typical RAS components for which redundancy may be*

considered. The RAS-entity should have a clear understanding of what components were applied to put a RAS into service and which were already present in the system before a RAS was installed. The RC will make the final determination regarding which components should be regarded as RAS components during its review".

· R5 – This requirement does not obligate RAS-entities to provide their results of the operational performance analysis of a RAS event to impacted Transmission Planners and Planning Coordinators. However, this action should be proposed in the Supplemental Material section.

· R6 – This requirement does not obligate RAS-entities to provide their Corrective Action Plans to impacted Transmission Planners and Planning Coordinators. However, this action should be proposed in the Supplemental Material section.

· R8 - The purpose of Version 6 of PRC-005 was to consolidate all maintenance and testing of relays under one Standard. Having RAS testing within PRC-012-2 would be contrary to that end. ATC proposes to address this concern as follows:

Functional testing of RAS (as stated in Requirement 8 of PRC-012-2) is a maintenance and testing activity that would be better included in the PRC-005 standard. The present PRC-005-6 Reliability Standard is the maintenance standard that replaces PRC-005-1, 008, 011 and 017 and was designed to cover the maintenance of SPSs/RASs. However, the current Reliability Standard PRC-005-6 lacks intervals and activities related to non-protective devices such as programmable logic controllers. ATC recommends that a requirement for maintenance and testing of non-protective RAS components be added to a revision of

PRC-005-6, rather than be an outlying maintenance requirement located in the PRC-012-2 Standard.

If the requirement is not removed and placed in PRC-005 standard, then we suggest that wording be added to R8 to refer the entity to meet the maintenance and testing interval obligations in the latest version of the PRC-005 standard.

Response:

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2

Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Answer Comment:

The rationale Box for R1 contains important guidelines for when a review of RAS is needed. These should be captured and retained in a standing Guideline. Also, there should be a need to review a RAS when the settings that initiate the RAS are changed – which may or may not be covered by the list of circumstances presented.

In the Applicability section of Attachment 3, the three entities identified for obligations to PRC-012-2 are explained with a concluding caveat that these entities can collaborate to meet the requirements of the standard.

“The standard does not stipulate particular compliance methods. RAS-entities have the option of collaborating to fulfill their responsibilities for each applicable requirement. Such collaboration and coordination may promote efficiency in achieving the reliability objectives of the requirements; however, the individual RAS-entity must be able to demonstrate its participation for compliance. As an example, the individual RAS-entities could collaborate to produce and submit a single, coordinated Attachment 1 to the reviewing RC pursuant to Requirement R1 to initiate the RAS review material to the process.”

We ask how will this allowance be included in the RSAW for this standard?

R6 should be clarified as proposed:

"Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of:"

Also, throughout the standard, references to days and months should be standardized. There are references to 60 calendar months, 6 calendar months, and 120 calendar days. These time periods should be expressed in either all months or all days to maintain consistency throughout the standard.

Response:

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments

Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Answer Comment:

The owner of **any** protection scheme should be responsible for the correct design and implementation of the scheme – RAS or not. Just like the design of switching to create a blackstart cranking path by a TOP in EOP-005-2, Requirement 6 must be verified by that TOP, the owner of the RAS should be held to the same expectation that the RAS is correctly designed and implemented. If the SDT still believes that some sort of review is required, then that review should be limited in scope to reviewing the generic content of the RAS design and not delve into the technical depth identified in some parts of Attachment 2.

Using the criteria outline by the SDT in its recent webinar, in addition to the independence of the reviewer and geographic span, the team also mentioned “expertise in planning, protection, operations, equipment”. The attributes of this expertise to the level expected do not currently exist in most RC organizations. RC’s are primarily operating entities (and even then primarily in real-time) and not experts in planning (beyond the operating time frame), protection or equipment. Transmission Owners, Transmission Operators and Transmission Planners normally have that expertise. The FERC acknowledged the limited RC technical expertise in evaluating details of restoration plans in its Order 749, Paragraph 38 (“…basis on which a

	reliability coordinator rejects a restoration plan will necessarily be based on generic engineering criteria…”). The review of a RAS by an RC should not be held to a higher expectation due to similar limited expertise with the equipment and systems involved in a RAS. The “flexibility” for the RC granted in the requirement to designate a third party would seem to immediately invalidate the original assumptions that the RC has the compelling capability to adequately perform the review while meeting the SDT’s characteristics of the reviewing entity. To allow this, while still requiring the RC to be responsible for the review, seems like an improper administrative burden and a potential compliance risk that the RC may assume because it had to find an entity more qualified than itself to perform the review. If an RC is not qualified to review all of the items in Attachment 2 then how can it be held responsible for the results of the review? Regarding the designation of a third party reviewer, clarification needs to be made regarding what it means to “retain the responsibility for compliance.” Does this simply mean that the review takes place or that there is some implied resulting responsibility for the correct design and implementation that the RC is now accountable for? Finally, also regarding the designation of a third party reviewer, is the term “third party” meant to be any entity not involved in the planning or implementation of the RAS? The alternative to using the RC? Although there appears to be a movement to remove the RRO as a responsible entity from all standards, those organizations through their membership expertise and committee structures more closely match the characteristics stated by

	the SDT – expertise in planning/protection/operations/equipment, independence by virtue of the diversity of its members, wide area perspective, and continuity. If for some reason the SDT, believes that the RRO still should not be involved then an alternative could be the Planning Coordinator function which should have similar expertise to the Transmission Planners that are to specify/design a RAS per the functional model yet would have some independence which the SDT is looking for.
Response:	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer Comment:	Requirement 4 of the standard requires the PC to assess the scheme once every 60 fully calendar months but the standard doesn't requires the RAS entity or RC to provide the PC with the information required to complete this assessment. Suggest adding an additional requirement for the RAS entity to provide data required to assessment the RAS within 30 days of receiving approval from the RC or within 30 calendar days of receiving a written request from the PC. The PC should also be receiving the information provided to the RC in R5.2, R6, R7.3. In Attachment 1 the following information appears to be request twice under the General and Description and Transmission Planning

Information. If the drafting team is intending different information be provided under the Description and Transmission Planning Information, please consider revising the statement to indicate what is expected.

• General item 4e and Description and Transmission Planning Information item 1

• General item 4f and Description and Transmission Planning Information item 2

• General item 4g and Description and Transmission Planning Information item 5

Response:

Steve Wenke - Avista - Avista Corporation - 5

Answer Comment: Moving the review of the RAS schemes up to the Reliabilty Coordinator level does not seem to be the best solution. This responsibility should fall to the Regional Entity.

Response:

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 – NPCC

Answer Comment:

Why the drafting team has not applied the same approach for RAS components ? Why non-protection system components associated to RAS cannot be subject to PRC-005 to avoid functional tests like protection systems components ?

For consistency, all analysis and mitigation of BES protection systems and RAS should be subject to the same standard. Hydro-Quebec TransEnergie suggests removing R5 of PRC-012 and adding into PRC-004.

For consistency, all maintenance and testing requirements of BES protection and control components, including RAS components, should be subject to the same criteria. For instance, the requirement R8 of PRC-012 does not distinguish monitored versus unmonitored devices.

Hydro-Quebec TransEnergie suggest removing R8 of PRC-012 and adding a table of ‘components used for RAS’ in PRC-005.

Response:

Mark Kenny - Eversource Energy - 3

Answer Comment:

Comments: Section 4.1.3 reads "Except for "limited impact"1 RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following:" Criteria 4.1.3.1 – 4.1.3.5 follow. Should this requirement also pertain to a failure to operate, which is the more severe consequence of have a single RAS component malfunction? Suggest the following wording change: "Except for "limited impact"1 RAS, the possible inadvertent operation or failure to operate of the RAS, resulting from any single RAS component malfunction satisfies all of the following:"

R6, second bullet item presently reads "Notifying the Reliability Coordinator pursuant to Requirements R5, or". To be clear, a CAP is only needed if the RAS fails to operate or if during the evaluation of an operation, a deficiency is confirmed. Suggest changing the language of this bullet to "Notifying the Reliability Coordinator of a deficiency or failure to operate pursuant to Requirements R5.2, or"

Use of the word "cannot" in footnote 1 is too restrictive and onerous for excluding a RAS from having to comply with the single component failure requirements in PRC-012-2. We suggest the Footnote 1 be revised to say: "A RAS designated as "limited impact" has been demonstrated through studies to not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations as a result of inadvertent operation or failure to operate. See Attachment 2 for a description of the limited impact determination by the Reliability Coordinator. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact for the purposes of Requirement 4, Parts 4.1.3 and 4.1.4."

R8 is vague and subject to interpretation. There are references in the supplemental material that suggest verification all of the logic in a RAS PLC on a periodic basis is required and yet in PRC-005, it's clear that there is no need to perform periodic maintenance on relay logic after it is commissioned. R8 also does not consider fully monitored components of the RAS such as in PRC-005.

Attachment 1, II.6 language should be modified similar to comment above to capture the possible RAS failure to operate due to a single RAS component malfunction. Suggest new wording: "Documentation describing the System performance resulting from the possible inadvertent operation or failure to operate of the RAS, except for limited impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be limited impact must satisfy all of the following:"

Attachment 1, III.3. statement appears to be only applicable to "limited impact" RAS. Wording of this item should be modified to reflect this. A limited impact RAS will still function correctly when a single component failure occurs or when a single component is taken out for maintenance. In all cases, reliability of a RAS scheme is impacted. It is not realistic to expect that reliability will not be compromised. It is unclear what the intent of this statement is.

Response:

Chris Gowder - Chris Gowder On Behalf of: Tom Reedy, Florida Municipal Power Pool, 6

Answer Comment:

FMPA is confused as to why the drafting team considers 60 full calendar months to be more consistent with PRC-014-0 than 5 calendar years, and views the later as extending the schedule (60 months = 5 years). FMPA's previous suggestion (see below) was not to "extend this schedule", but to make it more consistent with the annual Planning Assessment requirements of the TPL standard. A change to 5 calendar years would allow the Planning Coordinator to conduct their RAS evaluations in conjunction with their Planning Assessment, even if their process concludes in a different month in year 5 than it did in year 1. Requiring 60 calendar months versus 5 calendar years creates an unnecessary compliance burden that does not enhance reliability. The revision process should result in a standard that is more consistent with other active standards than its previous version, especially one that was never approved by FERC.

From the consideration of comments document…

"RAS Periodic Evaluations: Do you agree with the RAS planning evaluation process outlined by Requirement R4? If no, please provide the basis for your disagreement and an alternate proposal.

Selected Answer: Yes

Answer Comment: Recommend changing 60 full calendar months to 5 calendar years, to allow the RAS evaluation to fit within the annual Planning Assessment process which may vary from year to year.

Response: Thank you for your comment.

The drafting team based the 60 full calendar months schedule on the existing PRC-014-0, Requirement R1 to perform an assessment “at least once every five year. . .” The drafting team does not see a convincing reliability reason to further extend this schedule and declines to make the suggested change.”

Response:

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC

Group Name: LG&E and KU Energy, LLC

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E adn KU energy, LLC	SERC	1,3,5,6
justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6
Chjarlie Freibert	LG&E and KU Energy, LLC	SERC	3
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Dan Wilson	LG&E and KU Energy, LLC	SERC	5

Answer Comment:

These comments are submitted on behalf of Louisville Gas and Electric Company and Kentucky Utilities Company. ("LG&E/KU"). LG&E/KU are registered in one region (SERC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.

LG&E/KU strongly support the efforts the Standard Drafting Team has undertaken to provide in PRC-012 clear and unambiguous performance expectations and reliability benefits. LG&E/KU agree that the planning, design, periodic review, analysis and testing of SPS/RAS schemes are each essential components of maintaining BES reliability and that revising PRC-012 is a necessary and critical step towards that end.

LG&E/KU note that in Section 4 - Applicability of the latest draft of PRC-012, the functional entity "Planning Coordinator" has replaced "Transmission Planner." LG&E/KU support this change. However, while the current draft standard requires the Planning Coordinator to periodically review SPS/RAS schemes within the PC's planning region, the draft standard provides no role for the PC in approving any corrective action plan(s) developed to mitigate whatever threat(s) to BES reliability the PC's periodic review may have revealed. Moreover, and perhaps more importantly, there is likewise no requirement that the PC approve planned new or modified SPS/RAS schemes to insure consistency with procedures, protocols, and modeling methodology utilized with the relevant planning region. These omissions make it more difficult for the Planning Coordinator to coordinate and integrate the "transmission facility and service plans, resource plans, and protection system plans among the Transmission Planner(s) and Resource Planner(s) within its area of purview."[1]

LG&E/KU recognize that in some larger planning regions the Planning Coordinator ("PC") function may reside within the same organizational entity as the Transmission Owner ("TO") or Reliability Coordinator ("RC") functions. PRC-012, however, should function to promote and maintain BES reliability regardless of how the TO, PC and RC functions are distributed between organizational entities. Accordingly, LG&E/KU offer for the SDT's consideration the following changes to the draft requirements:

Requirement R1

Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) in consultation with the Planning Coordinator where the RAS is located.

Requirement R2

Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback developed in consultation with the Planning Coordinator to each RAS-entity.

Requirement R3

Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from the RAS-entity's Planning Coordinator and each reviewing Reliability Coordinator.

Requirement R5.2

Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s) and Planning Coordinator.

Requirement R6

Each RAS-entity shall participate in conjunction with the Planning Coordinator and Reliability Coordinator in developing a Corrective Action Plan (CAP) and submit the CAP to the RAS-entity's Planning Coordinator and Reliability Coordinator(s) within six full calendar months of:

Requirement R7.3

Notify each reviewing Reliability Coordinator and Planning Coordinator if CAP actions or timetables change and when the CAP is completed.

[1] NERC Reliability Functional Model Technical Document — Version 5, at p.10.

Response:

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Name: RSC no Con Edison, Hydro Quebec

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable

Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
David Burke	Orange and Rockland Utilities	NPCC	3
Wayne Sipperly	New York Power Authority	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7
Kathleen M. Goodman	ISO-New England	NPCC	2
Helen Lainis	Independent Electricity System Operator	NPCC	2

Michael Jones	National Grid	NPCC	3
Silvia Parada Mitchell	NextEra Energy	NPCC	4
Connie Lowe	Dominion	NPCC	4

Answer Comment:

R9 as written requires an update to the database to be made every 12 months. The Measure requires evidence that the database was updated. This would not address the situation where no update to the database was required because information did not change.

Reliability Standards usually use the phrase “review the information in the database and update as necessary”. Then the Measure becomes to present evidence that the review occurred and if a change occurred then the database was updated.

Section 4.1.3 reads “Except for “limited impact”1 RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following:” Criteria 4.1.3.1 – 4.1.3.5 follow. Should this requirement also pertain to a failure to operate, which is the more severe consequence of have a single RAS component malfunction? Suggest the following wording change: “Except for “limited impact”1 RAS, the possible inadvertent operation or failure to operate of the RAS, resulting from any single RAS component malfunction satisfies all of the following:”

R6, second bullet item presently reads “Notifying the Reliability Coordinator pursuant to Requirements R5, or”. To be clear a CAP is only needed if the RAS fails to operate or if during the evaluation of an operation, a deficiency is confirmed. Suggest changing the language of this bullet to “Notifying the Reliability Coordinator of a deficiency or failure to operate pursuant to Requirements R5.2, or”

Use of the word “cannot” in footnote 1 is too restrictive and onerous for excluding a RAS from having to comply with the single component failure requirements in PRC-012-2. We suggest the Footnote 1 be revised to say:

“A RAS designated as “limited impact” has been demonstrated by studies to not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations as a result of inadvertent operation or failure to operate. See Attachment 2 for a description of the limited impact determination by the Reliability Coordinator. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact for the purposes of Requirement 4, Parts 4.1.3 and 4.1.4.”

R8 is vague and subject to interpretation. There are references in the supplemental material that suggest maintenance checking all of the logic in a PLC on a periodic basis is required and yet in PRC-005, it’s clear that there is no need to perform periodic maintenance on relay logic. R8 also does not consider fully monitored components of the RAS such as in PRC-005.

Attachment 1, II.6 language should be modified similar to comment above to capture the possible RAS failure to operate due to a single RAS component malfunction. Suggest new wording: “Documentation describing the System performance resulting from the possible inadvertent operation or failure to operate of the RAS, except for limited impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be limited impact must satisfy all of the following:"

Attachment 1, III.3 statement appears to be only applicable to "limited impact" RAS. Wording of this item should be modified to reflect this. A limited impact RAS will still function correctly when a single component failure occurs or when a single component is taken out for maintenance. In all cases, reliability of a RAS scheme is impacted. It is not realistic to expect that reliability will not be compromised. It is unclear what the intent of this statement is.

While we support the proposed standard as presented, the word "participate" in Requirements R5, R6 and R8 can lead to confusion and may result in no entities being held responsible for initiating or leading the required tasks. As written, the RAS Entity needs only to participate in such tasks, but it is unclear on whose tasks are they or who leads these tasks.

We suggest remove the word "participate" from R5, R6 and R8 so that the RAS Entity is held responsible for analyzing the RAS operational performance in R5, developing a CAP in R6, and conducting functional test in R8. Note that the wording in the VSLs for R5, R6 and R8 clearly indicates that the RAS Entity is responsible for these tasks. Hence, the word "participate" in the above-mentioned three requirements is unnecessary and confusing.

We respectfully requests the STD to consider its previous comment; we believe that RAS should be reviewed and approved in both the planning and operating horizons by the designated entities within whose area(s) the Facility (ies) the RAS is designed to protect reside.

We believes that the term “in-kind” included in Footnote 4, “Changes to RAS hardware beyond in-kind replacement of existing components” is vague and suggests that the term be clarified such that the reader knows that the replacement of an electromechanical relay with a microprocessor relay is construed as an “in kind” replacement, as the drafting team noted in their December 15th presentation. The concept of “In-kind” replacement could be taken a step further. For example, a discrete ladder logic circuit that includes contacts, overcurrent and voltage relays could be replaced entirely inside the software logic of a multifunction device. From a black-box viewpoint, the old and new RAS would be identical in function. We also suggests for additional consideration that the replacement of many discrete components with a single multifunction component also be considered an “in kind” replacement so long as for a given set of inputs the “black box” produces the same outputs as the previous RAS would. In the case of a breaker failure event, the Standards Drafting Team “SDT” indicates the need for RAS redundancy even though that would be a double failure event (failure of the RAS and failure of the breaker). We suggests that it is sufficiently redundant to use the existing breaker failure relay (non-redundant) to initiate both RAS schemes. This can be accomplished by each RAS using a different contact off the breaker failure relay that was separately fused.

We suggests the SDT consider using a consistent measure of time, either calendar months or full calendar days, for responding and reporting. For example, Requirement 2 states: Each Reliability

	Coordinator that receives Attachment 1 information pursuant to Requirement R1, shall, within **four- full- calendar months** of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity." Whereas Requirement 4 states that: "Each RAS entity, within **120- full calendar days** of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall:"
Response:	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer Comment:	Reclamation appreciates the drafting team's consolidation of the terms RAS-owner and RAS-entity. Reclamation agrees with defining the RAS-entity as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. Reclamation also agrees with the drafting team's update to Requirement R6 that each RAS-entity shall participate in developing a CAP. Reclamation agrees that this collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service.

Reclamation supports the proposed change to the definition of SPS.

Response:

Rich Hydzik - Rich Hydzik On Behalf of: Bryan Cox, Avista - Avista Corporation, 5, 3, 1
Scott Kinney, Avista - Avista Corporation, 5, 3, 1

Answer Comment:

PRC-012-2 includes some very positive changes for the industry.

In R4.1.3, footnote 1 defines a “limited impact” RAS which does not require designing to a “no single point of failure” standard. It is a good thing to have this defined in a NERC standard.

Functional testing requirements defined to be every six years (R8). This is reasonable.

Evaluation of the need and performance of a RAS every six years is reasonable (R4).

However, there are concerns that prevent an “affirmative” vote for this standard.

The Reliability Coordinator is a function is defined as:

"The entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision."

This supports the concept of the RC reviewing the functionality and intended use of a RAS. However, a detailed RAS review also includes a design review of the RAS components and overall system design. This includes, but is not limited to, substation engineering, relay protection and design, telecommunication design and performance, and individual TOP operating practices. The RC's are familiar with the overall operation and performance of the BES. The RC's skill set generally does not include those technical specialties required for a detailed review of the design of a RAS.

This follows that the evaluation of a RAS misoperation should be performed by a different entity than the RC. While the RC certainly can evaluate the performance of the RAS and identify that a misoperation occurred, the RC's skill set does not allow for a thorough review of the RAS problem or potential solutions. Further, implementing a Corrective Action Plan under the supervision of the RC does not seem appropriate. This places the RC in an engineering, maintenance, and enforcement role that does not appear to be with the RC function.

	The intent of the standard is sound. Implementation among the Reliability Entities needs further development.
Response:	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer Comment:	**Degraded RAS** As Texas RE mentioned in the comments for the initial ballot, Texas RE recommends a requirement to report the degraded RAS to the RC. Texas RE noticed the referenced Standards/Requirements (i.e., Supplemental Material indicates PRC-001 R6 and TOP-001-2 R5) are either being retired or are not explicit enough to ensure that the reliability of the system is maintained for those who should have situational awareness. PRC-001 R6 is being retired and translated to TOP-001-3 R10 and R11 which applies to ONLY the TOP and BA not the RC. While TOP-003-3 states a BA and TOP "shall distribute its data specification to entities that have data required by the" respective functions and analysis (e.g., Real-time monitoring, Operational Planning Analyses), there is no requirement to provide the RAS status to the RC. **Requirement R8**

Texas RE is concerned introducing a six year functional testing requirement for a RAS is too long to ensure reliability of a system because reliability is at stake for the RAS to be in place. This extended timeframe may disregard PRC-005 components that may have shorter timeframes for maintenance or cause confusion to the entities responsible for said maintenance. While the RAS-entity will have PRC-005 obligations, it should not be considered the same as functional testing of the RAS if the PRC-005 components are ignored, overlooked, or not reviewed. Coordinated functional testing should be required for multi-RAS-entity owned RASs. Without coordination, there is not a clear reliability path to ensure overall performance and the proper operation of ALL RAS components.

Texas RE seeks clarity on the rationale for Requirement R8. It does not seem to reflect a coherent approach to reliability when discussing resetting the “test interval clock for that segment”. The Requirement is written for the RAS not segments of the RAS. The phrase “of its” that was added increases ambiguity and may cause confusion among RAS-entities in a multi-owned component RAS. Texas RE recommends requiring coordination of functional testing for RASs with components owned by more than one RAS-entity. Individualized non-coordinated functional testing of RAS components will not be a functional test of the RAS.

Full Calendar Months

The SDT introduces a new term “full calendar months” that is not defined and is inconsistent with other Reliability Standards. Texas Re recommends the SDT provide the definition within the auspices of the

Standards process while considering other definitions already in place (such as "Calendar Year" in PRC-005-2).

Corrective Action Plan

Texas RE recommends revising PRC-12-2, R7 to place at least minimal criteria around modifications to Corrective Action Plans (CAP) or corresponding CAP timetables. As currently drafted, PRC-12-2, R7 could be interpreted to permit RAS-entities to perpetually update their CAPs if "actions or timetables change" and then merely notify the RC of such changes. Texas RE recommends that the SDT consider some minimal criteria that RAS-entities must satisfy in order to update a CAP under PRC-12-2, R7.2. For instance, PRC-12-2, R7.2 could be revised to read: "Update the CAP for any reasonable changes in the required actions or implementation timetable." In turn, PRC-12-2, R7.3 could be revised to read: "Notify each reviewing Reliability Coordinator and provide a reasoned justification for changes in CAP actions or timetables, and notify each reviewing Reliability Coordinator when the CAP is completed."

RAS-entity definition

The current draft of PRC-12-2 defines the term "RAS-entity" in the Technical Justifications for Requirements section. Texas RE recommends that the SDT consider incorporating this definition into the language of PRC-12-2 itself or into the NERC Glossary of Terms.

Misoperations

In Requirement R5, what constitutes a RAS operation or

	misoperation? The NERC SPCS created a draft template in 2014 for reporting RAS operations and misoperations where they defined a misoperation as “Failure to Operate”, “Unnecessary Operation”, “Unintended System Response”, and “Failure to Mitigate”. These were draft terms and have not been incorporated into any Standard or the NERC Glossary. Arming and disarming of a RAS were not included in the SPCS RAS template. The items listed in 5.1.1 through 5.1.4 somewhat mirror the SPCS RAS template, is it the SDT’s intent that 5.1.1 through 5.1.4 are intended to be the definition of a RAS operation/misoperation? If so, Texas RE suggests these would be better suited in the NERC Glossary than within the Standard. Also reporting of Misoperations for Protection Systems will be contained with the Section 1600 Data Request for PRC-004. There is no requirement within PRC-012 or the Section 1600 data request for reporting Misoperations of a RAS to the Regional Entities or NERC. Texas RE recommends the SDT consider this.
Response:	
Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3	
Answer Comment:	1. Numerous entities, including TVA, have previously commented that the responsibility for reviewing and approving new or functionally

	modified RAS schemes belongs with the Planning Coordinator and not the Reliability Coordinator. According to the NERC Reliability Functional Model - Version 5, the Planning Coordinator is defined as the, "…entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facilities and services plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas." The model specifically includes the evaluation of transmission facilities in the planning horizon. Conversely, the Reliability Coordinator is responsible for maintaining the *Real-time* reliability of the Bulk Electric System. It was never contemplated that the Reliability Coordinator would have oversight over the planning of the Bulk Electric System or the entities responsible for Bulk Electric System planning. The drafting team's response to TVA's comments states that the Reliability Coordinator has the "widest-area reliability perspective of all functional entities" and that the "NERC Functional Model is a guideline" and does not preclude the drafting team from addressing functions not described in the Functional Model. From TVA's perspective, however, the proposed standard, as written, is in direct conflict with the Functional Model, and requires a compelling reason to justify the deviation. The facts that there are fewer Reliability Coordinators (as opposed to Planning Coordinators) and that the Reliability Coordinators have the "widest-area view" do not support a significant deviation from the Functional Model. Moreover, such analysis would beyond the normal Reliability Coordinator functions, the Reliability Coordinators would not have the expertise to conduct RAS analysis in the planning horizon. Simply put, Reliability Coordinators do not have trained personnel or the appropriate tools to complete a comprehensive assessment. Planning Coordinators have oversight over all other aspects of planning of the Bulk Electric System, and there is no reason to treat Remedial Action

	Schemes differently. R6 requires the "RAS-entity" to develop Corrective Action Plans if there is a deficiency in its 5-year RAS evaluation (R4), its post-event analysis (R5), or its 6-year functional testing (R8), and to submit those Corrective Action Plans to the Reliability Coordinator for review. The proposed standard, however, does not give the Reliability Coordinator any authority to approve or deny the Corrective Action Plan. If the Corrective Action Plan is inadequate or changes the RAS to cause a negative impact on a wider area of the BES, the Reliability Coordinator must be able to reject the Corrective Action Plan and require a revised plan.
Response:	

Eric Olson - Transmission Agency of Northern California - 1

Answer Comment:	TANC appreciates the drafting team's response to our prior comments and the corresponding changes to the standard regarding the potentially overlapping responsibilities of multiple Transmission Owners, Generator Owners and Distribution Providers that each own portions of a single RAS. In its response to TANC's prior comments, the drafting team stated that each RAS-entity "is responsible only for its RAS components." The second draft of the standard is not so clear on

	this issue, however, as the requirements only refer to each RAS-entity's responsibility for "its RAS". TANC requests that NERC replace "its RAS" with "its RAS components" in the requirements of the standard to clarify the responsibilities of each party. TANC believes that inserting this distinction into the language of the requirements would more clearly convey that multiple parties may have compliance responsibility for their respective "components" of a single RAS, but each party is not responsible for the entirety of the RAS. TANC notes that the "Reliability Standard PRC-012-2 Remedial Action Schemes Question & Answer Document" document dated November 2015 appears to incorrectly reference the Transmission Owner (TO) function in the first paragraph of Section 3. References in that paragraph were made to TO roles and responsibilities that are purportedly established within standards TOP-001-3 and IRO-005-4, but those two standards establish roles and responsibilities for the Transmission Operator (TOP) function, not the TO function.
Response:	

Mark Wilson - Independent Electricity System Operator - 2 - NPCC

Answer Comment:	While we support the proposed standard as presented, the word "participate" in Requirements R5, R6 and R8 can lead to confusion and

may result in no entities being held responsible for initiating or leading the required tasks. As written, the RAS Entity needs only to participate in such tasks, but it is unclear on whose tasks are they or who leads these tasks.

We suggest to remove the word “participate” from R5, R6 and R8 so that the RAS Entity is held responsible for analyzing the RAS operational performance in R5, developing a CAP in R6, and conducting functional test in R8. Note that the wording in the VSLs for R5, R6 and R8 clearly indicates that the RAS Entity is responsible for these tasks. Hence, the word “participate” in the above-mentioned three requirements is unnecessary and confusing.

Response:

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3
Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Answer Comment:

While Hydro One Networks Inc. is generally in support of the direction the standard takes and although the third revision (Draft 2- November 2015) presents improvement (with the introduction of the concept of “limited impact RAS” and recognition of RAS typing), requirement R8 and several choices in wording remain a concern. Hydro One believes that a level of testing similar to that required in the PRC-005 series would be more appropriate for R8. With a level of testing specified in

Comment #1 below, a high VRF, similar to that designated in the PRC-005 series would be appropriate and hence although Hydro One has cast a negative ballot on the standard, we are in support of the poll associated with the VRFs and VSLs. We hope the comments provided below will be of added value to the drafting team:

1. R8 is vague and subject to interpretation. There are references in the supplemental material that suggest maintenance and checking of all the logic in a PLC on a periodic basis is required, and yet, in PRC-005, it is clear that there is no need to perform periodic maintenance on relay logic. For monitored components, such as microprocessor relays, the "verification of settings [as] specified" in PRC-005 (i.e., performing a settings compare) should be sufficient rather than implying that all logic needs to be re-verified. For RAS not designated as limited-impact, R8 does not distinguish between monitored and unmonitored components of the RAS such as distinguished in PRC-005, which would allow a RAS-entity to have a 12-year maintenance interval for monitored components.

2. R5.1 – The usage of the term "*[p]articipate*" does not define accountability. The standard should clearly identify who is accountable for what activity. For consistency, we suggest using verbiage similar to that used in PRC-004-4's description of accountabilities in the case of owning Shared Protection Systems.

3. R5.1.3 & R5.1.4 are related to performance of RAS and its impact on the BES. This assessment is better suitable for the PC or RC to conduct.

4. R5.2 – "*Each RAS-entity shall provide results (…) to RC*". In the case

that a RAS is owned by more than one entity, it is unclear from the verbiage which entity is accountable to communicate with the RC and maintain evidence of such activity. The standard should clearly identify who is accountable for what activity. For consistency, we suggest using verbiage similar to that used in PRC-004-4's description of accountabilities in the case of owning Shared Protection Systems.

5. R6 - " *Each RAS-entity shall participate*" - Similar to the comments submitted above for R5, the usage of the term "*[p]articipate*" does not define accountability. The standard should clearly identify who is accountable for what activity. For consistency, we suggest using verbiage similar to that used in PRC-004-4's description of accountabilities in the case of owning Shared Protection Systems.

6. "*Each RAS-entity shall submit the CAP to RC*" - Similar to the comments submitted above for R5, in the case that a RAS is owned by multiple entities, it is unclear from the verbiage which entity is accountable to communicate with the RC and maintain evidence of such activity.

7. R5 – It is unclear from the wording whether the RAS-entity would "*[p]articipate in analyzing the RAS operational performance*" with the RC, or only mutually agree upon a schedule for such activity with the RC.

8. R4.1.4 - When a RAS is used to respond to an event, e.g. category P1 in TPL-001-4, its failure should be considered to be a more severe event, just as in TPL-001-4, the failure of a breaker or protection relay following a P1 event is recognized as "Multiple Contingency" (category P3 and P4). For this reason, the system performance with a RAS failure

should not be required to meet the exact same requirements as those for the original event (defined in TPL-001-4). Therefore, we suggest deleting R4.1.4 and instead revising R4.1.3 to read "Except for "limited impact"1 RAS, the possible inadvertent operation of the RAS, or failure of the RAS to operate, resulting from any single RAS component malfunction satisfies all of the following:"

9. RAS-entity: The standard should clearly define accountabilities in the case of a RAS scheme being owned by multiple entities.

10. R2 – We suggest specifying which entity the RC will be mutually agreeing upon a schedule with: "*on a schedule mutually agreed upon with the RAS-entity,….*"

Hydro One Networks Inc. also generally supports the comments the NPCC has submitted.

Response:

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Comment:

R2: BPA maintains that the allowance of up to four full calendar months for the RC to perform the RAS review is unreasonable and not in line with current regional practice.

Currently in WECC, RAS information for new or functionally modified schemes (this information is equivalent to Attachment 1 and 2) is provided two weeks in advance of scheduled WECC RAS RS meetings. At those meetings, all details of the RAS are presented, reviewed, and approved/disapproved. The review is at the final stages of the design process, just prior to construction/energization. By requiring Attachment 1, and Attachment 2, and allowing the RC four full calendar months review time, it appears that four months is being added to the entire process of placing a RAS in service. This additional four month delay may constrain the energization of variable generation resources.

Regarding Attachment 2: “**The RC review is not limited to the checklist items and the RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS.”** BPA believes this presents an open-ended opportunity to increase the four month review window, because you can’t go in service without prior approval of the RAS.

Attachment 2. II. 2. “**The timing of RAS actions(s) is appropriate to its BES performance objectives**.” This makes sense, but often timing of a RAS cannot be proven until the RAS is built and functionally tested. Historically in WECC, you are aware of the timing constraints required for RAS operation, you provide an estimate of the timing, and you’re provided “conditional approval” to go operational with a future action item presented to the WECC RAS RS that validates the timing is within constraints. Item 2 implies that a RAS-entity has to prove the timing prior to going in service, which isn’t reasonable. That basically means that the RAS-entity has to build the scheme, test it, and then go get it approved.

Attachment 2. II. 4. "**The RAS design facilitates periodic testing and maintenance**." BPA believes this is subjective; does this mean that the RC would require a standard method for periodic testing and maintenance? This appears open to interpretation.

The four full calendar months appears to create the opportunity for a large increase in workload and back and forth discussion between the RC and the utility designing the RAS.

R3: BPA proposes the requirement allow for conditional approval.

Response:

Ben Engelby - ACES Power Marketing - 6

Group Name: ACES Standards Collaborators - PRC-012-2 Project

Group Member Name	Entity	Region	Segments
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1

Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Ryan Strom	Buckeye Power, Inc.	RFC	4
Matt Caves	Western Farmers Electric Cooperative	SPP	1,5
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc. and Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Kevin Lyons	Central Iowa Power Cooperative	MRO	1
Mike Brytowski	Great River Energy	MRO	1,3,5,6

Answer Comment:

(1) We agree with the SDT's consolidation of the reliability objectives of the six existing RAS/SPS related standards into one standard PRC-012-2.

(2) The SAR for revising TPL-001-4 for single points of failure may overlap with PRC-012-2. We recommend the SDT meet with the SAR team to discuss the scope and potential for overlap that could lead to double jeopardy. We recommend that NERC staff also research this issue.

(3) RAS-entity causes confusion for entities that have joint ownership of

a RAS. We recommend the SDT develop guidance to support the requirements and expectations for joint owners to meet compliance. For RAS with multiple RAS-entities, who is responsible for overall coordination to assure complete and consistent data submittals in order to meet compliance with this standard? The SDT has left this silent, which may result in joint entities not cooperating, not sharing documentation, etc.

(4) Corrective Action Plans need to be clarified as to what triggers would qualify as a "deficiency" that would require a CAP to be developed. We also have concerns relating to coordination of CAPs that are developed for a jointly-owned RAS.

(5) We believe the VSLs for this standard could be better defined. The incremental scale between one criteria (e.g., R4 has 60, 61, 62, 63 calendar months for ranges from Lower to Severe) to the next for several VSLs are too condensed. We also believe a graduated scale for Requirements R1 and R3 could be provided.

(6) We agree that the RC is the best-suited entity to perform the RAS reviews. However, we recommend that the SDT actively work with RCs to ensure they are aware of the proposed requirements and have the resources to support them.

(7) We agree that the PC has a broader view compared to the TP and is the proper entity for RAS periodic evaluations.

(8) Finally, we ask NERC to consider the holiday schedule when posting standards for comment. There are several industry groups that coordinate comments a week or two prior to final submission to the

SDT, and having to coordinate comments over the holidays is difficult with vacation schedules. We ask the drafting teams to consider delaying posting so the deadline is the second or third week in January, allowing the industry groups enough time to coordinate during the weeks prior to the due date.

(9) Thank you for the opportunity to comment.

Response:

Phil Hart - Associated Electric Cooperative, Inc. - 1

Group Name: AECI

Group Member Name	Entity	Region	Segments
Mark Ramsey	N.W. Electric Power Cooperative, Inc.	SERC	1
John Stickley	N.W. Electric Power Cooperative, Inc.	SERC	3
Kevin White	Northeast Missouri Electric Power Cooperative	SERC	1

Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	SERC	3
Michael B Bax	Central Electric Power Cooperative	SERC	1
Adam M Weber	Central Electric Power Cooperative	SERC	3
Denise Stevens	Sho-Me Power Electric Cooperative	SERC	1
Jeff L Neas	Sho-Me Power Electric Cooperative	SERC	3
Walter Kenyon	KAMO Electric Cooperative	SERC	1
Theodore J Hilmes	KAMO Electric Cooperative	SERC	3
Phillip B Hart	Associated Electric Cooperative Inc.	SERC	1
Todd Bennett	Associated Electric Cooperative Inc.	SERC	3
Matt Pacobit	Associated Electric Cooperative Inc.	SERC	5
Brian Ackermann	Associated Electric Cooperative Inc.	SERC	6

Answer Comment: AECI is in agreement with multiple commenters who have issue with this current version.

Response:

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer Comment:	ERCOT supports the comments submitted by the IRC SRC and provides these additional comments. As noted above, ERCOT no longer uses the “Type 2” RAS designation, and this reference should be removed from the footnotes and rationale boxes in this draft standard. R6 should be reworded to clarify compliance obligations for the RAS-entity. ERCOT suggests the following language: “Each RAS-entity shall develop a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of:...." Additionally, the references to days and months should be standardized. There are references to 60 calendar months, 6 calendar months, and 120 calendar days. The SDT should consider expressing all of these time periods in the same units—using either months or days to maintain consistency throughout the standard.

Response:

Jared Shakespeare - Peak Reliability - 1

Answer Comment:	There needs to be some mechanism in place (possibly a requirement) to ensure that RAS functionality and coordination issues are addressed in response to physical changes to the system, e.g., removing or adding transmission or generation Facilities. A reliability gap can be created if the physical system is changed, but RAS are not updated or modified in response to those physical system changes. Without a functional modification to the RAS it would not perform according to its intended design. The five year review process cannot be relied upon to address these scenarios, as it would result in long-term exposure to reliability risks. Example scenario: {C}· A RAS exists in an area to prevent voltage collapse {C}· An entity retires a generation Facility which is associated with the RAS {C}· The RAS is not updated to account for the retirement of the generation Facility {C}· The RAS is rendered ineffective for preventing voltage collapse

{C}·		This condition is not discovered until the PC performs its 5-year review

{C}·		Until the PC performs its 5-year review, the system is vulnerable to voltage collapse due to RAS ineffectiveness

Both R4.1.4 and Attachment 1, section III, item 4 use the same confusing language, “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 is designed.” Though similar language is used in the currently effective set of reliability standards, it is confusing and unclear. We recommend clarifying the language and/or providing examples in an application guideline as part of the standard itself that might help the reader understand the meaning of and intent behind this language.

In R2 RC is required to follow Attachment 2 for the evaluation, what is the required evaluation for the PC in R4? Is it Attachment 2 as well?

For R5 when a RAS operation, failure to operate, or mis-operation occurs, and a deficiency is identified, the RAS should be removed from service until the CAP is implemented.

Response:

End of report

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

Draft 2 of PRC-012-2 corrects the applicability of the fill-in-the-blank standards (PRC-012-1, PRC-013-1, and PRC-014-1) by assigning the requirement responsibilities to the specific users, owners, and operators of the Bulk-Power System, and incorporates the reliability objectives of all the RAS-related standards. This draft contains nine requirements and measures, the associated rationale boxes and corresponding technical guidelines. There are also three attachments within the draft standard that are incorporated via references in the requirements. This draft of PRC-012-2 is posted for a 45-day formal comment period with a parallel ballot in the last ten days of the comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	February 12, 2014
SAR posted for comment	February 18, 2014
Standards Committee approved the SAR	June 10, 2014
Draft 1 of PRC-012-2 posted for informal comment	April 30 – May 20, 2015
45-day formal comment period with initial ballot	August 20 – October 5, 2015
45-day formal comment period with additional ballot	November 25, 2015 – January 8, 2016
45-day formal comment period with additional ballot	February 3, 2016 – March 18, 2016

Anticipated Actions	Date
10-day final ballot	April 2016
NERC Board (Board) adoption	May 2016

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Remedial Action Schemes
2. **Number:** PRC-012-2
3. **Purpose:** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).
4. **Applicability:**
    - **4.1. Functional Entities:**
        - **4.1.1.** Reliability Coordinator
        - **4.1.2.** Planning Coordinator
        - **4.1.3.** RAS-entity – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS
    - **4.2. Facilities:**
        - **4.2.1.** Remedial Action Schemes (RAS)
5. **Effective Date:** See the Implementation Plan for PRC-012-2.

B. Requirements and Measures

Rationale for Requirement R1: Each Remedial Action Scheme (RAS) is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES). Therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification or retirement; i.e., removal from service must be completed prior to implementation or retirement.

Functional modifications consist of any of the following:

- Changes to System conditions or Contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

To facilitate a review that promotes reliability, the RAS-entity must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity provide them to the reviewing Reliability Coordinator (RC). The RC (reviewing RC) that coordinates the area where the RAS is located is responsible for the review. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate and submit a single, coordinated Attachment 1 to the reviewing RC. In cases where a RAS crosses RC Area boundaries, each affected RC is responsible for conducting either individual reviews or participating in a coordinated review.

R1. Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, a copy of the Attachment 1 documentation and the dated communications with the reviewing Reliability Coordinator(s) in accordance with Requirement R1.

Rationale for Requirement R2: The RC is the functional entity best suited to perform the RAS review because it has the widest-area operational and reliability perspective of all functional entities and an awareness of reliability issues in any neighboring RC Area. This Wide Area purview facilitates the evaluation of interactions among separate RAS as well as interactions among RAS and other protection and control systems. Review by the RC also minimizes the possibility of a conflict of interest that could exist because of business relationships among the RAS-entity, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC is not expected to possess more information or ability than anticipated by their

functional registration as designated by NERC. The RC may request assistance to perform RAS reviews from other parties such as the PC or regional technical groups; however, the RC will retain the responsibility for compliance with this requirement.

Attachment 2 of this standard is a checklist the RC can use to identify design and implementation aspects of RAS and facilitate consistent reviews for each submitted RAS. The time frame of four full calendar months is consistent with current utility and regional practice; however, flexibility is provided by allowing the RC(s) and RAS-entity(ies) to negotiate a mutually agreed upon schedule for the review.

Note: An RC may need to include this task in its reliability plan(s) for the NERC Regions(s) in which it is located.

R2. Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated reports, checklists, or other documentation detailing the RAS review, and the dated communications with the RAS-entity in accordance with Requirement R2.

Rationale for Requirement R3: The RC review is intended to identify reliability issues that must be resolved before the RAS can be put in-service. Examples of reliability issues include a lack of dependability, security, or coordination.

A specific time period for the RAS-entity to respond to the reviewing RC following identification of any reliability issue(s) is not necessary because the RAS-entity wants to expedite the timely approval and subsequent implementation of the RAS.

A specific time period for the RC to respond to the RAS-entity following the RAS review is also not necessary because the RC will be aware of (1) any reliability issues associated with the RAS not being in service and (2) the RAS-entity's schedule to implement the RAS to address those reliability issues. Since the RC is the ultimate arbiter of BES operating reliability, resolving reliability issues is a priority for the RC and serves as an incentive to expeditiously respond to the RAS-entity.

R3. Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Acceptable evidence may include, but is not limited to, dated documentation and communications with the reviewing Reliability Coordinator that no reliability issues

were identified during the review or that all identified reliability issues were resolved in accordance with Requirement R3.

Rationale for Requirement R4: Requirement R4 mandates that an evaluation of each RAS be performed at least once every five full calendar years. The purpose of the periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that, if a RAS single component malfunction or single component failure were to occur, the requirements for BES performance would continue to be satisfied. A periodic evaluation is required because changes in System topology or operating conditions may change the effectiveness of a RAS or the way it impacts the BES.

RAS are unique and customized assemblages of protection and control equipment that vary in complexity and impact on the reliability of the BES. In recognition of these differences, RAS can be designated by the reviewing RC(s) as limited impact. A limited impact RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. Limited impact RAS are not subject to the RAS single component malfunction and failure tests of Parts 4.1.4 and 4.1.5, respectively. Requiring a limited impact RAS to meet these tests would add complexity to the design with minimal benefit to BES reliability. See the Supplemental Material for more on the limited impact designation.

The limited impact designation is modeled after the Local Area Protection Scheme (LAPS) classification in WECC (Western Electricity Coordinating Council) and the Type 3 classification in NPCC (Northeast Power Coordinating Council). A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type 3 in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.

For existing RAS, the initial performance of Requirement R4 must be completed within five full calendar years of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within five full calendar years of the RAS approval date by the reviewing RC(s). Five full calendar years was selected as the maximum time frame between evaluations based on the time frames for similar requirements in Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation can be performed sooner if it is determined that material changes to System topology or System operating conditions could potentially impact the effectiveness or coordination of the RAS. System changes also have the potential to alter the reliability impact of limited impact RAS on the BES. Requirement 4, Part 4.1.3 explicitly requires the periodic evaluation of limited impact RAS to verify the limited impact designation remains applicable. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluations (Requirement R4, Parts 4.1.1 through 4.1.5) are planning analyses that may involve modeling of the interconnected transmission system to assess BES performance. The Planning Coordinator (PC) is the functional entity best suited to perform this evaluation because they have a wide area planning perspective. To promote reliability, the PC is required to provide the results of the evaluation to each impacted Transmission Planner and Planning Coordinator, in addition to each reviewing RC and RAS-entity. In cases where a RAS crosses PC boundaries, each affected PC is responsible for conducting either individual evaluations or participating in a coordinated evaluation.

The previous version of this standard (PRC-012-1 Requirement 1, R1.4) states "… 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." Requirement R4 clarifies that the inadvertent operation to be considered would only be that caused by the malfunction of a single RAS component. This allows security features to be designed into the RAS such that inadvertent operation due to a single component malfunction is prevented. Otherwise, consistent with PRC-012-1 Requirement 1, R1.4, the RAS should be designed so that its whole or partial inadvertent operation due to a single component malfunction satisfies the System 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 some other Contingency or System condition not defined in TPL-001-4 (therefore without performance requirements), its inadvertent operation still must meet some minimum System performance requirements. However, instead of referring to the TPL-001-4, Requirement R4 lists the System performance requirements that the inadvertent operation must satisfy. The performance requirements listed (Parts 4.1.3.1 – 4.1.3.5) are the ones that are common to all planning events P0-P7 listed in TPL-001-4.

R4. Each Planning Coordinator, at least once every five full calendar years, shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Perform an evaluation of each RAS within its planning area to determine whether:

4.1.1. The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed.

4.1.2. The RAS avoids adverse interactions with other RAS, and protection and control systems.

4.1.3. For limited impact[1] RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

4.1.4. Except for limited impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following:

4.1.4.1. The BES shall remain stable.

4.1.4.2. Cascading shall not occur.

4.1.4.3. Applicable Facility Ratings shall not be exceeded.

4.1.4.4. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

4.1.4.5. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

4.1.5. Except for limited impact RAS, 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 is designed.

4.2. Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.

M4. Acceptable evidence may include, but is not limited to, dated reports or other documentation of the analyses comprising the evaluation(s) of each RAS and dated communications with the RAS-entity(ies), Transmission Planner(s), Planning Coordinator(s), and the reviewing Reliability Coordinator(s) in accordance with Requirement R4.

[1] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

Rationale for Requirement R5: The correct operation of a RAS is important for maintaining the reliability and integrity of the BES. Any incorrect operation of a RAS indicates that the RAS effectiveness and/or coordination has been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: 1) verify RAS operation was consistent with the implemented design; or 2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120 full calendar day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation. To promote reliability, each RAS-entity is required to provide the results of RAS operational performance analyses that identified any deficiencies to its reviewing RC(s).

RAS-entities may need to collaborate with their associated Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation was triggered correctly (Part 5.1.1), responded as designed (Part 5.1.2), and that the resulting BES response (Parts 5.1.3 and 5.1.4) was consistent with the intended functionality and design of the RAS. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to conduct and submit a single, coordinated operational performance analysis.

R5. Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Participate in analyzing the RAS operational performance to determine whether:

5.1.1. The System events and/or conditions appropriately triggered the RAS.

5.1.2. The RAS responded as designed.

5.1.3. The RAS was effective in mitigating BES performance issues it was designed to address.

5.1.4. The RAS operation resulted in any unintended or adverse BES response.

5.2. Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).

M5. Acceptable evidence may include, but is not limited to, dated documentation detailing the results of the RAS operational performance analysis and dated communications with participating RAS-entities and the reviewing Reliability Coordinator(s) in accordance with Requirement R5.

Rationale for Requirement R6: Deficiencies identified in the periodic RAS evaluation conducted by the PC pursuant to Requirement R4, in the operational performance analysis conducted by the RAS-entity pursuant to Requirement R5, or in the functional test performed by the RAS-entity pursuant to Requirement R8, potentially pose a reliability risk to the BES. To mitigate these potential reliability risks, Requirement R6 mandates that each RAS-entity develop a Corrective Action Plan (CAP) to address the identified deficiency. The CAP contains the mitigation actions and associated timetable necessary to remedy the specific deficiency. The RAS-entity may request assistance with CAP development from other parties such as its Transmission Planner or Planning Coordinator; however, the RAS-entity has the responsibility for compliance with this requirement.

If the CAP requires that a functional change be made to a RAS, the RAS-entity will need to submit information identified in Attachment 1 to the reviewing RC(s) prior to placing RAS modifications in-service per Requirement R1.

Depending on the complexity of the identified deficiency(ies), development of a CAP may require studies, and other engineering or consulting work. A maximum time frame of six full calendar months is specified for RAS-entity collaboration on the CAP development. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to develop and submit a single, coordinated CAP.

R6. Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

- Being notified of a deficiency in its RAS pursuant to Requirement R4, or
- Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or
- Identifying a deficiency in its RAS pursuant to Requirement R8.

M6. Acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each reviewing Reliability Coordinator and each RAS-entity in accordance with Requirement R6.

Rationale for Requirement R7: Requirement R7 mandates each RAS-entity implement a CAP (developed in Requirement R6) that mitigates the deficiencies identified in Requirements R4, R5, or R8. By definition, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem." The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. Each reviewing Reliability Coordinator must be notified if CAP actions or timetables change, and when the CAP is completed.

R7. Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

7.1. Implement the CAP.

7.2. Update the CAP if actions or timetables change.

7.3. Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

M7. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, and communication with the reviewing Reliability Coordinator(s) that documents the implementation, updating, or completion of a CAP in accordance with Requirement R7.

Rationale for Requirement R8: Due to the wide variety of RAS designs and implementations, and the potential for impacting BES reliability, it is important that periodic functional testing of a RAS be performed. A functional test provides an overall confirmation of the RAS to operate as designed and verifies the proper operation of the non-Protection System (control) components of a RAS that are not addressed in PRC-005. Protection System components that are part of a RAS are maintained in accordance with PRC-005.

The six or twelve full calendar year test interval, which begins on the effective date of the standard pursuant to the PRC-012-2 implementation plan, is a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS. Extending to longer intervals increases the reliability risk to the BES posed by an undiscovered latent failure that could cause an incorrect operation or failure of the RAS. The RAS-entity is in the best position to determine the testing procedure and schedule due to its overall knowledge of the RAS design, installation, and functionality. Functional testing may be accomplished with end-to-end testing or a segmented approach. For segmented testing, each segment of a RAS must be tested. Overlapping segments can be tested individually negating the need for complex maintenance schedules and outages.

> The maximum allowable interval between functional tests is six full calendar years for RAS that are not designated as limited impact RAS and twelve full calendar years for RAS that are designated as limited impact RAS. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. A correct operation of a RAS qualifies as a functional test for those RAS segments which operate (documentation for compliance with Requirement R5 Part 5.1). If an event causes a partial operation of a RAS, the segments without an operation will require a separate functional test within the maximum interval with the starting date determined by the previous successful test of the segments that did not operate.

R8. Each RAS-entity shall participate in performing a functional test of each of its RAS to verify the overall RAS performance and the proper operation of non-Protection System components: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

- At least once every six full calendar years for all RAS not designated as limited impact, or
- At least once every twelve full calendar years for all RAS designated as limited impact

M8. Acceptable evidence may include, but is not limited to, dated documentation detailing the RAS operational performance analysis for a correct RAS segment or an end-to-end operation (Measure M5 documentation), or dated documentation demonstrating that a functional test of each RAS segment or an end-to-end test was performed in accordance with Requirement R8.

Rationale for Requirement R9: The RAS database is a comprehensive record of all RAS existing in a Reliability Coordinator Area. The database enables the RC to provide other entities high-level information on existing RAS that could potentially impact the operational and/or planning activities of that entity. Attachment 3 lists the minimum information required for the RAS database, which includes a summary of the RAS initiating conditions, corrective actions, and System issues being mitigated. This information allows an entity to evaluate the reliability need for requesting more detailed information from the RAS-entities identified in the database contact information. The RC is the appropriate entity to maintain the database because the RC receives the required database information when a new or modified RAS is submitted for review. The twelve full calendar month time frame is aligned with industry practice and allows sufficient time for the RC to collect the appropriate information from RAS-entities and update the RAS database.

R9. Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once every twelve full calendar months. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M9. Acceptable evidence may include, but is not limited to, dated spreadsheets, database reports, or other documentation demonstrating a RAS database was updated in accordance with Requirement R9.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The RAS-entity (Transmission Owner, Generator Owner, and Distribution Provider) shall each keep data or evidence to show compliance with Requirements R1, R3, R5, R6, R7, and R8, and Measures M1, M3, M5, M6, M7, and M8 since the last audit, unless directed by its Compliance Enforcement

Authority to retain specific evidence for a longer period of time as part of an investigation.

The Reliability Coordinator shall each keep data or evidence to show compliance with Requirements R2 and R9, and Measures M2 and M9 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Planning Coordinator shall each keep data or evidence to show compliance with Requirement R4 and Measure M4 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a RAS-entity (Transmission Owner, Generator Owner or Distribution Provider), Reliability Coordinator, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The RAS-entity failed to provide the information identified in Attachment 1 to each Reliability Coordinator prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R1.
R2.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90 full calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in accordance with Requirement R2.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	N/A	N/A	N/A	The RAS-entity failed to resolve identified reliability issue(s) to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R3.
R4.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but was late by less than or equal to 30 full calendar days.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate one of the Parts 4.1.1 through 4.1.5.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but was late by more than 90 full calendar days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate two or more of the Parts 4.1.1 through 4.1.5. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to provide the results to one or more of the receiving entities listed in Part 4.2. OR The Planning Coordinator failed to perform the evaluation in accordance with Requirement R4.
R5.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by less than or equal to 10 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address one of the Parts 5.1.1 through 5.1.4.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address two or more of the Parts 5.1.1 through 5.1.4.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to provide the results (Part 5.2) to one or more of the reviewing Reliability Coordinator(s). OR The RAS-entity failed to perform the analysis in accordance with Requirement R5.
R6.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30 full calendar days. OR The RAS-entity developed a Corrective Action Plan but failed to submit it to one or

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				more of its reviewing Reliability Coordinator(s) in accordance with Requirement R6. OR The RAS-entity failed to develop a Corrective Action Plan in accordance with Requirement R6.
R7.	The RAS-entity implemented a CAP in accordance with Requirement R7, Part 7.1, but failed to update the CAP (Part 7.2) if actions or timetables changed, or failed to notify (Part 7.3) each of the reviewing Reliability Coordinator(s) of the updated CAP or completion of the CAP.	N/A	N/A	The RAS-entity failed to implement a CAP in accordance with Requirement R7, Part 7.1.
R8.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by less than or equal to 30 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 30 full calendar days	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 60 full calendar days	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 90 full calendar days.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		but less than or equal to 60 full calendar days.	but less than or equal to 90 full calendar days.	OR The RAS-entity failed to perform the functional test for a RAS as specified in Requirement R8.
R9.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90 full calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

D. Regional Variances

None.

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
1		Adopted by NERC Board of Trustees	New

Attachment 1
Supporting Documentation for RAS Review

The following checklist identifies important Remedial Action Scheme (RAS) information for each new or functionally modified[2] RAS that the RAS-entity must document and provide to the reviewing Reliability Coordinator(s) (RC). If an item on this list does not apply to a specific RAS, a response of "Not Applicable" for that item is appropriate. When RAS are submitted for functional modification review and approval, only the proposed modifications to that RAS require review; however, the RAS-entity must provide a summary of the existing functionality. The RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS. Additional entities (without decision authority) may be part of the RAS review process at the request of the RC.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.
2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.
3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP.
4. Data to populate the RAS database:
    a. RAS name.
    b. Each RAS-entity and contact information.
    c. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
    d. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
    e. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
    f. Action(s) to be taken by the RAS.

[2] Functionally Modified: Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

g. Identification of limited impact[3] RAS.

h. Any additional explanation relevant to high-level understanding of the RAS.

II. Functional Description and Transmission Planning Information

1. Contingencies and System conditions that the RAS is intended to remedy.
2. The action(s) to be taken by the RAS in response to disturbance conditions.
3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and the date those technical studies were performed.
4. Information regarding any future System plans that will impact the RAS.
5. RAS-entity proposal and justification for limited impact designation, if applicable.
6. Documentation describing the System performance resulting from the possible inadvertent operation of the RAS, except for limited impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be limited impact must satisfy all of the following:
   a. The BES shall remain stable.
   b. Cascading shall not occur.
   c. Applicable Facility Ratings shall not be exceeded.
   d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.
   e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.
7. An evaluation indicating that the RAS settings and operation avoid adverse interactions with other RAS, and protection and control systems.
8. Identification of other affected RCs.

[3] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

III. Implementation

1. Documentation describing the applicable equipment used for detection, dc supply, communications, transfer trip, logic processing, control actions, and monitoring.
2. Information on detection logic and settings/parameters that control the operation of the RAS.
3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in-service or is being maintained.
4. Documentation describing the System performance resulting from a single component failure in the RAS, except for limited impact RAS, when the RAS is intended to operate. A single component failure in a RAS not determined to be limited impact must 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 is designed. The documentation should describe or illustrate how the design achieves this objective.
5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies RAS information that the RAS-entity shall document and provide to each reviewing RC.

1. Information necessary to ensure that the RC is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of applicable technical studies and technical justifications upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

Attachment 2
Reliability Coordinator RAS Review Checklist

The following checklist identifies reliability-related considerations for the Reliability Coordinator (RC) to review and verify for each new or functionally modified[4] Remedial Action Scheme (RAS). The RC review is not limited to the checklist items and the RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS. If a checklist item is not relevant to a particular RAS, it should be noted as “Not Applicable.” If reliability considerations are identified during the review, the considerations and the proposed resolutions should be documented with the remaining applicable Attachment 2 items.

I. Design

1. The RAS actions satisfy performance objectives for the scope of events and conditions that the RAS is intended to mitigate.
2. The designed timing of RAS operation(s) is appropriate to its BES performance objectives.
3. The RAS arming conditions, if applicable, are appropriate to its System performance objectives.
4. The RAS avoids adverse interactions with other RAS, and protection and control systems.
5. The effects of RAS incorrect operation, including inadvertent operation and failure to operate, have been identified.
6. Determination whether or not the RAS is limited impact.[5] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.
7. Except for limited impact RAS as determined by the RC, the possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following:
   a. The BES shall remain stable.
   b. Cascading shall not occur.
   c. Applicable Facility Ratings shall not be exceeded.

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[4] Functionally Modified: Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

[5] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

   d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

   e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

8. The effects of future BES modifications on the design and operation of the RAS have been identified, where applicable.

II. Implementation

1. The implementation of RAS logic appropriately correlates desired actions (outputs) with events and conditions (inputs).
2. Except for limited impact RAS as determined by the RC, a single component failure in a RAS does not prevent the BES from meeting the same performance requirements as those required for the events and conditions for which the RAS is designed.
3. The RAS design facilitates periodic testing and maintenance.
4. The mechanism or procedure by which the RAS is armed is clearly described, and is appropriate for reliable arming and operation of the RAS for the conditions and events for which it is designed to operate.

III. RAS Retirement

RAS retirement reviews should assure that there is adequate justification for why a RAS is no longer needed.

Attachment 3
Database Information

1. RAS name.
2. Each RAS-entity and contact information.
3. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
5. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
6. Action(s) to be taken by the RAS.
7. Identification of limited impact[6] RAS.
8. Any additional explanation relevant to high-level understanding of the RAS.

[6] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

Technical Justification

4.1.1 Reliability Coordinator

The Reliability Coordinator (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. The Wide-Area purview 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, Planning Coordinator, Transmission Planner, or other entities 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.

4.1.2 Planning Coordinator

The Planning Coordinator (PC) is the best-suited functional entity to perform the RAS evaluation 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, similar to the planning analyses performed by PCs.

4.1.3 RAS-entity

The RAS-entity is any Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If all of the RAS (RAS components) have a single owner, then that RAS-entity has sole responsibility for all the activities assigned within the standard to the RAS-entity. If the RAS (RAS components) have more than one owner, then each separate RAS component owner is a RAS-entity and is obligated to participate in various activities identified by the Requirements.

The standard does not stipulate particular compliance methods. RAS-entities have the option of collaborating to fulfill their responsibilities for each applicable requirement. Such collaboration and coordination may promote efficiency in achieving the reliability objectives of the requirements; however, the individual RAS-entity must be able to demonstrate its participation for compliance. As an example, the individual RAS-entities could collaborate to produce and submit a single, coordinated Attachment 1 to the reviewing RC pursuant to Requirement R1 to initiate the RAS review process.

Limited impact

RAS are unique and customized assemblages of protection and control equipment that vary in complexity and impact on the reliability of the BES. These differences in RAS design, action, and risk to the BES are identified and verified within the construct of Requirements R1-R4 of PRC-012-2.

The reviewing RC has the authority to designate a RAS as limited impact if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. The reviewing RC is the sole arbiter for determining whether a RAS qualifies for the limited impact designation. The limited impact designation is available to any RAS in any Region provided the reviewing RC determines the RAS poses a low risk to BES reliability.

The limited impact designation is modeled after the Local Area Protection Scheme (LAPS) classification in WECC (Western Electricity Coordinating Council) and the Type 3 classification in NPCC (Northeast Power Coordinating Council). The following information describing the aforementioned WECC and NPCC RAS is excerpted from the respective regional documentation[7].The drafting team notes that the information below represents the state of the WECC and NPCC regional processes at the time of this standard development and is subject to change before the effective date of PRC-012-2.

WECC: Local Area Protection Scheme (LAPS)

A Remedial Action Scheme (RAS) whose failure to operate would NOT result in any of the following:

- Violations of TPL-001-WECC-RBP System Performance RBP,
- Maximum load loss ≥ 300 MW,
- Maximum generation loss ≥ 1000 MW.

NPCC: Type III

An SPS whose misoperation or failure to operate results in no **significant adverse impact** outside the **local area**.

The following terms are also defined by NPCC to assess the impact of the SPS for classification:

Significant adverse impact – With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from faults or disturbances, shall be deemed as having significant adverse impact:

a. system instability;
b. unacceptable system dynamic response or equipment tripping;
c. voltage levels in violation of applicable emergency limits;
d. loadings on transmission facilities in violation of applicable emergency limits;
e. unacceptable loss of load.

Local area – An electrically confined or radial portion of the system. The geographic size and number of system elements contained will vary based on system characteristics. A local area may be relatively large geographically with relatively few buses in a sparse system, or be

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[7] WECC Procedure to Submit a RAS for Assessment Information Required to Assess the Reliability of a RAS Guideline, Revised 10/28/2013 | NPCC Regional Reliability Reference Directory # 7, Special Protection Systems, Version 2, 3/31/2015

relatively small geographically with a relatively large number of buses in a densely networked system.

Because the drafting team modeled the limited impact designation after the WECC and NPCC classifications, each RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type 3 in NPCC, is recognized as a limited impact RAS upon the effective date of PRC-012-2 and is subject to all applicable requirements.

To propose an existing RAS (a RAS implemented prior to the effective date of PRC-012-2) be designated as limited impact by the reviewing RC, the RAS-entity must prepare and submit the appropriate Attachment 1 information that includes the technical justification (evaluations) documenting that the System can meet the performance requirements (specified in Requirement R4, Parts 4.1.4 and 4.1.5) resulting from a single RAS component malfunction or failure, respectively.

There is nothing that precludes a RAS-entity from working with the reviewing RC during the implementation period of PRC-012-2, in anticipation of the standard becoming enforceable. However, even if the reviewing RC determines the RAS qualifies as limited impact, the designation is not relevant until the standard becomes effective. Until then, the existing regional processes remain in effect as well as the existing RAS classifications or lack thereof.

An example of a scheme that could be recognized as a limited impact RAS is a load shedding or generation rejection scheme used to mitigate the overload of a BES transmission line. The inadvertent operation of such a scheme would cause the loss of either a certain amount of generation or load. The evaluation by the RAS-entity should demonstrate that the loss of this amount of generation or load, without the associated contingency for RAS operation actually occurring, is acceptable and not detrimental to the reliability of BES; e.g., in terms of frequency and voltage stability. The failure of that scheme to operate when intended could potentially lead to the overloading of a transmission line beyond its acceptable rating. The RAS-entity would need to demonstrate that this overload, while in excess of the applicable Facility Rating, is not detrimental to the BES outside the contained area (predetermined by studies) affected by the contingency.

Another example of a limited-impact RAS is a scheme used to protect BES equipment from damage caused by overvoltage through generation rejection or equipment tripping.

Another example of a limited-impact RAS is a centrally-controlled undervoltage load shedding scheme used to protect a contained area (predetermined by studies) of the BES against voltage collapse.

Requirement R1

Each RAS is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES); therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification, or retirement (removal from service) must be completed prior to implementation.

Functional modifications consists of any of the following:

- Changes to System conditions or Contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

An example indicating the limits of an in-kind replacement of a RAS component is the replacement of one relay (or other device) with a relay (or other device) that uses similar functions. For instance, if a RAS included a CO-11 relay which was replaced by an IAC-53 relay, that would be an in-kind replacement. If the CO-11 relay were replaced by a microprocessor SEL-451 relay that used only the same functions as the original CO-11 relay, that would also be an in-kind replacement; however, if the SEL-451 relay was used to add new logic to what the CO-11 relay had provided, then the replacement relay would be a functional modification.

Changes to RAS pickup levels that require no other scheme changes are not considered a functional modification. For example, System conditions require a RAS to be armed when the combined flow on two lines exceeds 500 MW. If a periodic evaluation pursuant to Requirement R4, or other assessment, indicates that the arming level should be reduced to 450 MW without requiring any other RAS changes that would not be a functional modification. Similarly, if a RAS is designed to shed load to reduce loading on a particular line below 1000 amps, then a change in the load shedding trigger from 1000 amps to 1100 amps would not be a functional modification.

Another example illustrates a case where a System change may result in a RAS functional change. Assume that a generation center is connected to a load center through two transmission lines. The lines are not rated to accommodate full plant output if one line is out of service, so a RAS monitors the status of both lines and trips or ramps down the generation to a safe level following loss of either line. Later, one of the lines is tapped to serve additional load. The System that the RAS impacts now includes three lines, loss of any of which is likely to still require generation reduction. The modified RAS will need to monitor all three lines (add two line terminal status inputs to the RAS) and the logic to recognize the specific line outages would change, while the generation reduction (RAS output) requirement may or may not change, depending on which line is out of service. These required RAS changes would be a functional modification.

Any functional modification to a RAS will need to be reviewed and approved through the process described in Requirements R1, R2, and R3. The need for such functional modifications may be identified in several ways including but not limited to the Planning evaluations pursuant to R4, incorrect operations pursuant to R5, a test failure pursuant to R8, or Planning assessments related to future additions or modifications of other facilities.

To facilitate a review that promotes reliability, the RAS-entity(ies) must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity(ies) provide them to the reviewing Reliability Coordinator (RC). The RC that coordinates the area where the RAS is located is responsible for the review. In cases where a RAS crosses multiple RC Area boundaries, each affected RC is responsible for conducting either individual reviews or a coordinated review.

Requirement R1 does not specify how far in advance of implementation the RAS-entity(ies) must provide Attachment 1 data to the reviewing RC. The information will need to be submitted early enough to allow RC review in the allotted time pursuant to Requirement R2, including resolution of any reliability issues that might be identified, in order to obtain approval of the reviewing RC. Expeditious submittal of this information is in the interest of each RAS-entity to effect a timely implementation.

Requirement R2

Requirement R2 mandates that the RC perform reviews of all proposed new RAS and existing RAS proposed for functional modification, or retirement (removal from service) in its RC Area.

RAS are unique and customized assemblages of protection and control equipment. As such, they have a potential to introduce reliability risks to the BES, if not carefully planned, designed, and installed. A RAS may be installed to address a reliability issue, or achieve an economic or operational advantage, and could introduce reliability risks that might not be apparent to a RAS-entity(ies). An independent review by a multi-disciplinary panel of subject matter experts with planning, operations, protection, telecommunications, and equipment expertise is an effective means of identifying risks and recommending RAS modifications when necessary.

The RC is the functional entity best suited to perform the RAS reviews because it has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. This Wide Area purview facilitates the evaluation of interactions among separate RAS as well as interactions among the 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, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC may request assistance in RAS reviews from other parties such as the PC(s) or regional technical groups (e.g., Regional Entities); however, the RC retains responsibility for compliance with the requirement. It is recognized that the RC does not possesses more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not contain compliance requirements. If Reliability Standards address functions that are not described in the model, the Reliability Standard requirements take precedence over the Functional Model. For further reference, please see the Introduction section of NERC’s Reliability Functional Model, Version 5, November 2009.

Attachment 2 of this standard is a checklist for assisting the RC in identifying design and implementation aspects of a RAS, and for facilitating consistent reviews of each RAS submitted for review. The time frame of four full calendar months is consistent with current utility practice; however, flexibility is provided by allowing the parties to negotiate a different schedule for the review. Note, an RC may need to include this task in its reliability plan(s) for the NERC Region(s) in which it is located.

Requirement R3

Requirement R3 mandates that each RAS-entity resolve all reliability issues (pertaining to its RAS) identified during the RAS review by the reviewing Reliability Coordinators. Examples of reliability issues include a lack of dependability, security, or coordination. RC approval of a RAS is considered to be obtained when the reviewing RC's feedback to each RAS-entity indicates that either no reliability issues were identified during the review or all identified reliability issues were resolved to the RC's satisfaction.

Dependability is a component of reliability that is the measure of certainty of a device to operate when required. If a RAS is installed to meet performance requirements of NERC Reliability Standards, a failure of the RAS to operate when intended would put the System at risk of violating NERC Reliability Standards if specified Contingency(ies) or System conditions occur. This risk is mitigated by designing the RAS so that it will accomplish the intended purpose while experiencing a single RAS component failure. This is often accomplished through redundancy. Other strategies for providing dependability include "over-tripping" load or generation, or alternative automatic backup schemes.

Security is a component of reliability that is the measure of certainty of a device to not operate inadvertently. False or inadvertent operation of a RAS results in taking a programmed action without the appropriate arming conditions, occurrence of specified Contingency(ies), or System conditions expected to trigger the RAS action. Typical RAS actions include shedding load or generation or re-configuring the System. Such actions, if inadvertently taken, are undesirable and may put the System in a less secure state. Worst case impacts from inadvertent operation often occur if all programmed RAS actions occur. If the System performance still satisfies PRC-012-2 Requirement R4, Part 4.3, no additional mitigation is required. Security enhancements to the RAS design, such as voting schemes, are acceptable mitigations against inadvertent operations.

Any reliability issue identified during the review must be resolved before implementing the RAS to avoid placing the System at unacceptable risk. The RAS-entity or the reviewing RC(s) may have alternative ideas or methods available to resolve the issue(s). In either case, the concern needs to be resolved in deference to reliability, and the RC has the final decision.

A specific time period for the RAS-entity to respond to the RC(s) review is not necessary because an expeditious response is in the interest of each RAS-entity to effect a timely implementation.

A specific time period for the RC to respond to the RAS-entity following the RAS review is also not necessary because the RC will be aware of (1) any reliability issues associated with the RAS not being in service and (2) the RAS-entity's schedule to implement the RAS to address those reliability issues. Since the RC is the ultimate arbiter of BES operating reliability, resolving reliability issues is a priority for the RC and serves as an incentive to expeditiously respond to the RAS-entity.

Requirement R4

Requirement R4 mandates that an evaluation of each RAS be performed at least once every five full calendar years. The purpose of a periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that requirements for BES performance following inadvertent RAS operation and single component failure continue to be satisfied. A periodic evaluation is required because changes in System topology or operating conditions may change the effectiveness of a RAS or the way it interacts with and impacts the BES.

A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. Limited impact RAS are not subject to the RAS single component malfunction and failure tests of Parts 4.1.4 and 4.1.5, respectively. Requiring a limited impact RAS to meet these tests would add complexity to the design with minimal benefit to BES reliability.

A RAS implemented after the effective date of this standard can only be designated as limited impact by the reviewing RC(s). A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type 3 in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.

Requirement R4 also clarifies that the RAS single component failure and inadvertent operation tests do not apply to RAS which are determined to be limited impact. Requiring a limited impact RAS to meet the single component failure and inadvertent operation tests would just add complexity to the design with little or no improvement in the reliability of the BES.

For existing RAS, the initial performance of Requirement R4 must be completed within five full calendar years of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within five full calendar years of the RAS approval date by the reviewing RC(s). Five full calendar years was selected as the maximum time frame between evaluations based on the time frames for similar requirements in Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation can be performed sooner if it is determined that material changes to System topology or System operating conditions could potentially impact the effectiveness or coordination of the RAS. System changes also have the potential to alter the reliability impact of limited impact RAS on the BES. Requirement 4, Part 4.1.3 explicitly requires the periodic evaluation of limited impact RAS to verify the limited impact designation remains applicable. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluations (Requirement R4, Parts 4.1.1 through 4.1.5) are planning analyses that may involve modeling of the interconnected transmission system to assess BES performance. The PC is the functional entity best suited to perform the analyses because they have a wide-area planning perspective. To promote reliability, the PC is required to provide the results of the evaluation to each impacted Transmission Planner and Planning Coordinator, in addition to each reviewing RC and RAS-entity. In cases where a RAS crosses PC boundaries, each affected PC is responsible for conducting either individual evaluations or participating in a coordinated evaluation.

The intent of Requirement R4, Part 4.1.4 is to require that the possible inadvertent operation of the RAS (other than limited impact RAS), caused by the malfunction of a single component of the RAS, meet the same System performance requirements as those required for the Contingency(ies) or System conditions for which it is designed. If the RAS is designed to meet one of the planning events (P0-P7) in TPL-001-4, the possible inadvertent operation of the RAS must meet the same performance requirements listed in the standard for that planning event. The requirement clarifies that the inadvertent operation to be considered is only that caused by the malfunction of a single RAS component. This allows features to be designed into the RAS to improve security, such that inadvertent operation due to malfunction of a single component is prevented; otherwise, the RAS inadvertent operation must satisfy Requirement R4, Part 4.1.4.

The intent of Requirement R4, Part 4.1.4 is also to require that the possible inadvertent operation of the RAS (other than limited impact RAS) installed for an extreme event in TPL-001-4 or for some other Contingency or System conditions not defined in TPL-001-4 (therefore without performance requirements), meet the minimum System performance requirements of Category P7 in Table 1 of NERC Reliability Standard TPL-001-4. However, instead of referring to the TPL standard, the requirement lists the System performance requirements that a potential inadvertent operation must satisfy. The performance requirements listed (Requirement R4, Parts 4.1.4.1 – 4.1.4.5) are the ones that are common to all planning events (P0-P7) listed in TPL-001-4.

With reference to Requirement 4, Part 4.1.4, note that the only differences in performance requirements among the TPL (P0-P7) events (not common to all of them) concern Non-Consequential Load Loss and interruption of Firm Transmission Service. It is not necessary for Requirement R4, Part 4.1.4 to specify performance requirements related to these areas because a RAS is only allowed to drop non-consequential load or interrupt Firm Transmission Service if that action is allowed for the Contingency for which it is designed. Therefore, the inadvertent operation should automatically meet Non-Consequential Load Loss or interrupting Firm Transmission Service performance requirements for the Contingency(ies) for which it was designed.

Part 4.1.5 requires that a single component failure in the RAS (other than limited impact 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 is designed. This analysis is needed to ensure that changing System conditions do not result in the single component failure requirement not being met.

Requirements for inadvertent RAS operation (Requirement R4, Part 4.1.4) and single component failure (Requirement R4, Part 4.1.5) are reviewed by the reviewing RC(s) before a new or functionally modified RAS is placed in-service, and are typically satisfied by specific design considerations. Although the scope of the periodic evaluation does not include a new design review, it is possible that a design which previously satisfied requirements for inadvertent RAS operation and single component failure may fail to satisfy these requirements at a later time, and must be evaluated with respect to the current System. For example, if the actions of a particular RAS include tripping load, load growth could occur over time that impacts the amount of load to be tripped. These changes could result in tripping too much load upon inadvertent operation and result in violations of Facility Ratings. Alternatively, the RAS might be designed to trip more load than necessary (i.e., "over trip") in order to satisfy single component failure requirements. System changes could result in too little load being tripped and unacceptable BES performance if one of the loads failed to trip.

Requirement R5

The correct operation of a RAS is important to maintain the reliability and integrity of the BES. Any incorrect operation of a RAS indicates the RAS effectiveness and/or coordination may have been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: (1) verify RAS operation is consistent with implemented design; or (2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120 full calendar day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation; however, flexibility is provided by allowing the parties to negotiate a different schedule for the analysis. To promote reliability, the RAS-entity(s) is required to provide the results of RAS operational performance analyses to its reviewing RC(s) if the analyses revealed a deficiency.

The RAS-entity(ies) may need to collaborate with its associated Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation was triggered correctly (Part 5.1.1), responded as designed (Part 5.1.2), and that the resulting BES response (Parts 5.1.3 and 5.1.4) was consistent with the intended functionality and design of the RAS. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to conduct and submit a single, coordinated operational performance analysis.

Requirement R6

RAS deficiencies potentially pose a reliability risk to the BES. RAS deficiencies may be identified in the periodic RAS evaluation conducted by the PC in Requirement R4, in the operational analysis conducted by the RAS-entity in Requirement R5, or in the functional test performed by the RAS-entity(ies) in Requirement R8. To mitigate potential reliability risks, Requirement R6

mandates that each RAS-entity participate in developing a CAP that establishes the mitigation actions and timetable necessary to address the deficiency.

The RAS-entity(ies) that owns the RAS components, is responsible for the RAS equipment, and is in the best position to develop the timelines and perform the necessary work to correct RAS deficiencies. If necessary, the RAS-entity(ies) may request assistance with development of the CAP from other parties such as its Transmission Planner or Planning Coordinator; however, the RAS-entity has the responsibility for compliance with this requirement.

A CAP may require functional changes be made to a RAS. In this case, Attachment 1 information must be submitted to the reviewing RC(s), an RC review must be performed to obtain RC approval before the RAS-entity can place RAS modifications in-service, per Requirements R1, R2, and R3.

Depending on the complexity of the issues, development of a CAP may require study, engineering or consulting work. A timeframe of six full calendar months is allotted to allow enough time for RAS-entity collaboration on the CAP development, while ensuring that deficiencies are addressed in a reasonable time. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to develop and submit a single, coordinated CAP. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the RAS deficiency is resolved. The possibility of such operating restrictions will incent the RAS-entity to resolve the issue as quickly as possible.

The following are example situations of when a CAP is required:

- A determination after a RAS operation/non-operation investigation that the RAS did not meet performance expectations or did not operate as designed.
- Periodic planning assessment reveals RAS changes are necessary to correct performance or coordination issues.
- Equipment failures.
- Functional testing identifies that a RAS is not operating as designed.

Requirement R7

Requirement R7 mandates that each RAS-entity implement its CAP developed in Requirement R6 which mitigates the deficiencies identified in Requirements R4, R5, or R8. By definition, a CAP is: “A list of actions and an associated timetable for implementation to remedy a specific problem.”

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. If the CAP is changed, the RAS-entity must notify the reviewing Reliability Coordinator(s). The RAS-entity must also notify the Reliability Coordinator(s) when the CAP has been completed.

The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions will incent the RAS-entity to complete the CAP as quickly as possible.

Requirement R8

The reliability objective of Requirement R8 is to test the non-Protection System components of a RAS (controllers such as programmable logic controllers (PLCs)) and to verify the overall performance of the RAS through functional testing. Functional tests validate RAS operation by ensuring System states are detected and processed, and that actions taken by the controls are correct and occur within the expected time using the in-service settings and logic. Functional testing is aimed at assuring overall RAS performance and not the component focused testing contained in the PRC-005 maintenance standard.

Since the functional test operates the RAS under controlled conditions with known System states and expected results, testing and analysis can be performed with minimum impact to the BES and should align with expected results. The RAS-entity is in the best position to determine the testing procedure and schedule due to their overall knowledge of the RAS design, installation, and functionality. Periodic testing provides the RAS-entity assurance that latent failures may be identified and also promotes identification of changes in the System that may have introduced latent failures.

The six and twelve full calendar year functional testing intervals are greater than the annual or bi-annual periodic testing performed in some NERC Regions. However, these intervals are a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS. Longer test intervals for limited impact RAS are acceptable because incorrect operations or failures to operate present a low reliability risk to the Bulk Power System.

Functional testing is not synonymous with end-to-end testing. End-to-end testing is an acceptable method but may not be feasible for many RAS. When end-to-end testing is not possible, a RAS-entity may use a segmented functional testing approach. The segments can be tested individually negating the need for complex maintenance schedules. In addition, actual RAS operation(s) can be used to fulfill the functional testing requirement. If a RAS does not operate in its entirety during a System event or System conditions do not allow an end-to-end scheme test, then the segmented approach should be used to fulfill this Requirement. Functional testing includes the testing of all RAS inputs used for detection, arming, operating, and data collection. Functional testing, by default operates the processing logic and infrastructure of a RAS, but focuses on the RAS inputs as well as the actions initiated by RAS outputs to address the System condition(s) for which the RAS is designed. All segments and components of a RAS must be tested or have proven operations within the applicable maximum test interval to demonstrate compliance with the Requirement.

As an example of segment testing, consider a RAS controller implemented using a PLC that receives System data, such as loading or line status, from distributed devices. These distributed devices could include meters, protective relays, or other PLCs. In this example RAS, a line protective relay is used to provide an analog metering quantity to the RAS control PLC. A functional test would verify that the System data is received from the protective relay by the PLC, processed by the PLC, and that PLC outputs are appropriate. There is no need to verify the protective relay's ability to measure the power system quantities, as this is a requirement for Protection Systems used as RAS in PRC-005, Table 1-1, Component Type – Protective Relay. Rather the functional test is focused on the use of the protective relay data at the PLC, including the communications data path from relay to PLC if this data is essential for proper RAS operation. Additionally, if the control signal back to the protective relay is also critical to the proper functioning of this example RAS, then that path is also verified up-to the protective relay. This example describes a test for one segment of a RAS which verifies RAS action, verifies PLC control logic, and verifies RAS communications.

IEEE C37.233, "IEEE Guide for Power System Protection Testing," 2009 section 8 (particularly 8.3-8.5), provides an overview of functional testing. The following opens section 8.3:

> Proper implementation requires a well-defined and coordinated test plan for performance evaluation of the overall system during agreed maintenance intervals. The maintenance test plan, also referred to as functional system testing, should include inputs, outputs, communication, logic, and throughput timing tests. The functional tests are generally not component-level testing, rather overall system testing. Some of the input tests may need to be done ahead of overall system testing to the extent that the tests affect the overall performance. The test coordinator or coordinators need to have full knowledge of the intent of the scheme, isolation points, simulation scenarios, and restoration to normal procedures.
>
> The concept is to validate the overall performance of the scheme, including the logic where applicable, to validate the overall throughput times against system modeling for different types of Contingencies, and to verify scheme performance as well as the inputs and outputs.

If a RAS passes a functional test, it is not necessary to provide that specific information to the RC because that is the expected result and requires no further action. If a segment of a RAS fails a functional test, the status of that degraded RAS is required to be reported (in Real-time) to the Transmission Operator via PRC-001, Requirement R6, then to the RC via TOP-001-3, Requirement R8. See Phase 2 of Project 2007-06 for the mapping document from PRC-001 to other standards regarding notification of RC by TOP if a deficiency is found during testing. Consequently, it is not necessary to include a similar requirement in this standard.

The initial test interval begins on the effective date of the standard pursuant to the implementation plan. Subsequently, the maximum allowable interval between functional tests is six full calendar years for RAS that are not designated as limited impact RAS and twelve full calendar years for RAS that are designated as limited impact RAS. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. A RAS-entity may choose to count a correct RAS operation as a qualifying functional test for those RAS segments which operate. If a System event causes a correct, but partial RAS operation, separate functional tests of the segments that did not operate are still required within the maximum test interval that started on the date of the previous successful test of those (non-operating) segments in order to be compliant with Requirement R8.

Requirement R9

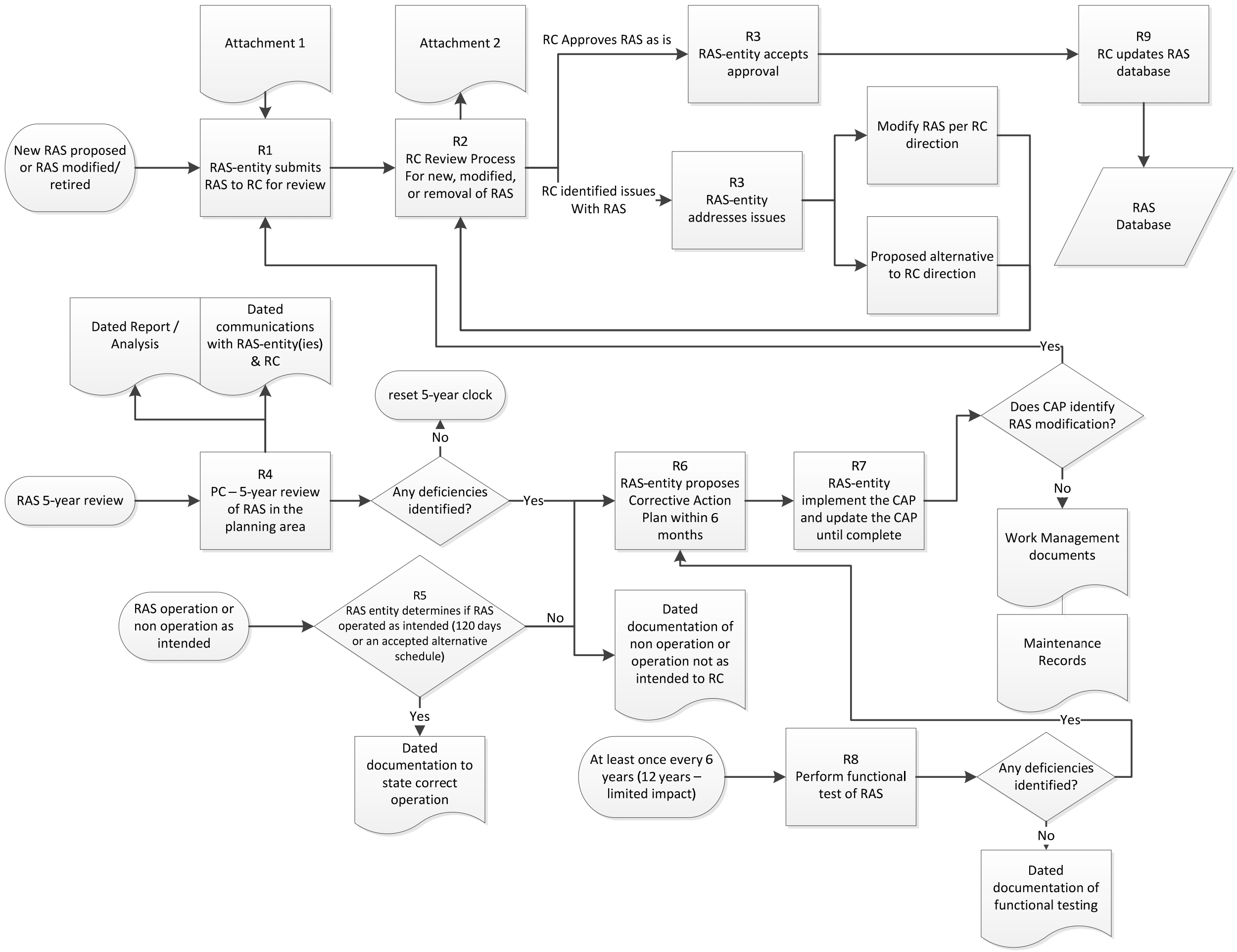
The RAS database required to be maintained by the RC in Requirement R9 ensures information regarding existing RAS is available. Attachment 3 contains the minimum information that is required to be included about each RAS listed in the database. Additional information can be requested by the RC.

The database enables the RC to provide other entities high-level information on existing RAS that could potentially impact the operational and/or planning activities of that entity. The information provided is sufficient for an entity with a reliability need to evaluate whether the RAS can impact its System. For example, a RAS performing generation rejection to mitigate an overload on a transmission line may cause a power flow change within an adjacent entity area. This entity should be able to evaluate the risk that a RAS poses to its System from the high-level information provided in the RAS database.

The RAS database does not need to list detailed settings or modeling information, but the description of the System performance issues, System conditions, and the intended corrective actions must be included. If additional details about the RAS operation are required, the entity may obtain the contact information of the RAS-entity from the RC.

Process Flow Diagram

The diagram below depicts the process flow of the PRC-012-2 requirements.



Technical Justifications for Attachment 1 Content
Supporting Documentation for RAS Review

To perform an adequate review of the expected reliability implications of a Remedial Action Scheme (RAS), it is necessary for the RAS-entity(ies) to provide a detailed list of information describing the RAS to the reviewing RC. If there are multiple RAS-entities for a single RAS, information will be needed from all RAS-entities. Ideally, in such cases, a single RAS-entity will take the lead to compile all the data identified into a single Attachment 1.

The necessary data ranges from a general overview of the RAS to summarized results of transmission planning studies, to information about hardware used to implement the RAS. Coordination between the RAS and other RAS and protection and control systems will be examined for possible adverse interactions. This review can include wide-ranging electrical design issues involving the specific hardware, logic, telecommunications, and other relevant equipment and controls that make up the RAS.

Attachment 1

The following checklist identifies important RAS information for each new or functionally modified[8] RAS that the RAS-entity shall document and provide to the RC for review pursuant to Requirement R1. When a RAS has been previously reviewed, only the proposed modifications to that RAS require review; however, it will be helpful to each reviewing RC if the RAS-entity provides a summary of the existing RAS functionality.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.

   Provide a description of the RAS to give an overall understanding of the functionality and a map showing the location of the RAS. Identify other protection and control systems requiring coordination with the RAS. See RAS Design below for additional information.

   Provide a single-line drawing(s) showing all sites involved. The drawing(s) should provide sufficient information to allow the RC review team to assess design reliability, and should include information such as the bus arrangement, circuit breakers, the associated switches, etc. For each site, indicate whether detection, logic, action, or a combination of these is present.

2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.

3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP. [Reference NERC Reliability Standard PRC-012-2, Requirements R5 and R7]

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[8] Functionally Modified: Any modification to a RAS consisting of any of the following:

- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

Provide a description of any functional modifications to a RAS that are part of a CAP that are proposed to address performance deficiency(ies) identified in the periodic evaluation pursuant to Requirement R4, the analysis of an actual RAS operation pursuant to Requirement R5, or functional test failure pursuant to Requirement R8. A copy of the most recent CAP must be submitted in addition to the other data specified in Attachment 1.

4. Initial data to populate the RAS database.

   a. RAS name.

   b. Each RAS-entity and contact information.

   c. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent five full calendar year (Requirement R4) evaluation date; and, date of retirement, if applicable.

   d. System performance issue or reason for installing the RAS (*e.g.*, thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery).

   e. Description of the Contingencies or System conditions for which the RAS was designed (initiating conditions).

   f. Corrective action taken by the RAS.

   g. Identification of limited impact[9] RAS.

   h. Any additional explanation relevant to high level understanding of the RAS.

   Note: This is the same information as is identified in Attachment 3. Supplying the data at this point in the review process ensures a more complete review and minimizes any administrative burden on the reviewing RC(s).

II. Functional Description and Transmission Planning Information

1. Contingencies and System conditions that the RAS is intended to remedy. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.1]

   a. The System conditions that would result if no RAS action occurred should be identified.

   b. Include a description of the System conditions that should arm the RAS so as to be ready to take action upon subsequent occurrence of the critical System Contingencies or other operating conditions when RAS action is intended to occur. If no arming conditions are required, this should also be stated.

   c. Event-based RAS are triggered by specific Contingencies that initiate mitigating action. Condition-based RAS may also be initiated by specific Contingencies, but

[9] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

specific Contingencies are not always required. These triggering Contingencies and/or conditions should be identified.

2. The actions to be taken by the RAS in response to disturbance conditions. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.2]

   Mitigating actions are designed to result in acceptable System performance. These actions should be identified, including any time constraints and/or "backup" mitigating measures that may be required in case of a single RAS component failure.

3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and the date those technical studies were performed. [Reference NEC Reliability Standard PRC-014, R3.2]

   Review the scheme purpose and impact to ensure it is (still) necessary, serves the intended purposes, and meets current performance requirements. While copies of the full, detailed studies may not be necessary, any abbreviated descriptions of the studies must be detailed enough to allow the reviewing RC(s) to be convinced of the need for the scheme and the results of RAS-related operations.

4. Information regarding any future System plans that will impact the RAS. [Reference NERC Reliability Standard PRC-014, R3.2]

   The RC's other responsibilities under the NERC Reliability Standards focus on the Operating Horizon, rather than the Planning Horizon. As such, the RC is less likely to be aware of any longer range plans that may have an impact on the proposed RAS. Such knowledge of future Plans is helpful to provide perspective on the capabilities of the RAS.

5. RAS-entity proposal and justification for limited impact designation, if applicable.

   A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type 3 in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.

6. Documentation describing the System performance resulting from the possible inadvertent operation of the RAS, except for limited impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be limited impact must satisfy all of the following: [Reference NERC Reliability Standard PRC-012, R1.4]

   a. The BES shall remain stable.

b. Cascading shall not occur.

c. Applicable Facility Ratings shall not be exceeded.

d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

7. An evaluation indicating that the RAS settings and operation avoids adverse interactions with other RAS, and protection and control systems.
   [Reference NERC Reliability Standards PRC-012, R1.5 and PRC-014, R3.4]

   RAS are complex schemes that may take action such as tripping load or generation or re-configuring the System. Many RAS depend on sensing specific System configurations to determine whether they need to arm or take actions. An examples of an adverse interaction: A RAS that reconfigures the System also changes the available fault duty, which can affect distance relay overcurrent ("fault detector") supervision and ground overcurrent protection coordination.

8. Identification of other affected RCs.

   This information is needed to aid in information exchange among all affected entities and coordination of the RAS with other RAS and protection and control systems.

III. Implementation

1. Documentation describing the applicable equipment used for detection, dc supply, communications, transfer trip, logic processing, control actions, and monitoring.

   Detection
   Detection and initiating devices, whether for arming or triggering action, should be designed to be secure. Several types of devices have been commonly used as disturbance, condition, or status detectors:

   - Line open status (event detectors),
   - Protective relay inputs and outputs (event and parameter detectors),
   - Transducer and IED (analog) inputs (parameter and response detectors),
   - Rate of change (parameter and response detectors).

   DC Supply
   Batteries and charges, or other forms of dc supply for RAS, are commonly also used for Protection Systems. This is acceptable, and maintenance of such supplies is covered by PRC-005. However, redundant RAS systems, when used, should be supplied from separately protected (fused or breakered) circuits.

Communications: Telecommunications Channels

Telecommunications channels used for sending and receiving RAS information between sites and/or transfer trip devices should meet at least the same criteria as other relaying protection communication channels. Discuss performance of any non-deterministic communication systems used (such as Ethernet).

The scheme logic should be designed so that loss of the channel, noise, or other channel or equipment failure will not result in a false operation of the scheme.

It is highly desirable that the channel equipment and communications media (power line carrier, microwave, optical fiber, etc.) be owned and maintained by the RAS-entity, or perhaps leased from another entity familiar with the necessary reliability requirements. All channel equipment should be monitored and alarmed to the dispatch center so that timely diagnostic and repair action shall take place upon failure. Publicly switched telephone networks are generally an undesirable option.

Communication channels should be well labeled or identified so that the personnel working on the channel can readily identify the proper circuit. Channels between entities should be identified with a common name at all terminals.

Transfer Trip

Transfer trip equipment, when separate from other RAS equipment, should be monitored and labeled similarly to the channel equipment.

Logic Processing

All RAS require some form of logic processing to determine the action to take when the scheme is triggered. Required actions are always scheme dependent. Different actions may be required at different arming levels or for different Contingencies. Scheme logic may be achievable by something as simple as wiring a few auxiliary relay contacts or by much more complex logic processing.

Platforms that have been used reliably and successfully include PLCs in various forms, personal computers (PCs), microprocessor protective relays, remote terminal units (RTUs), and logic processors. Single-function relays have been used historically to implement RAS, but this approach is now less common except for very simple new RAS or minor additions to existing RAS.

Control Actions

RAS action devices may include a variety of equipment such as transfer trip, protective relays, and other control devices. These devices receive commands from the logic processing function (perhaps through telecommunication facilities) and initiate RAS actions at the sites where action is required.

Monitoring by SCADA/EMS should include at least

- Whether the scheme is in-service or out of service.
  - For RAS that are armed manually, the arming status may be the same as whether the RAS is in-service or out of service.

  - For RAS that are armed automatically, these two states are independent because a RAS that has been placed in-service may be armed or unarmed based on whether the automatic arming criteria have been met.
- The current operational state of the scheme (available or not).
- In cases where the RAS requires single component failure performance; e.g., redundancy, the minimal status indications should be provided separately for each system.
  - The minimum status is generally sufficient for operational purposes; however, where possible it is often useful to provide additional information regarding partial failures or the status of critical components to allow the RAS-entity to more efficiently troubleshoot a reported failure. Whether this capability exists will depend in part on the design and vintage of equipment used in the RAS. While all schemes should provide the minimum level of monitoring, new schemes should be designed with the objective of providing monitoring at least similar to what is provided for microprocessor-based Protection Systems.

2. Information on detection logic and settings/parameters that control the operation of the RAS. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.3]

   Several methods to determine line or other equipment status are in common use, often in combination:

   a. Auxiliary switch contacts from circuit breakers and disconnect switches (52a/b, 89a/b)—the most common status monitor; “a” contacts exactly emulate actual breaker status, while “b” contacts are opposite to the status of the breaker;

   b. Undercurrent detection—a low level indicates an open condition, including at the far end of a line; pickup is typically slightly above the total line-charging current;

   c. Breaker trip coil current monitoring—typically used when high-speed RAS response is required, but usually in combination with auxiliary switch contacts and/or other detection because the trip coil current ceases when the breaker opens; and

   d. Other detectors such as angle, voltage, power, frequency, rate of change of the aforementioned, out of step, etc. are dependent on specific scheme requirements, but some forms may substitute for or enhance other monitoring described in items ‘a’, ‘b’, and ‘c’ above.

   Both RAS arming and action triggers often require monitoring of analog quantities such as power, current, and voltage at one or more locations and are set to detect a specific level of the pertinent quantity. These monitors may be relays, meters, transducers, or other devices

3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in-service or is being maintained.

In this context, a multifunction device (e.g., microprocessor-based relay) is a single component that is used to perform the function of a RAS in addition to protective relaying and/or SCADA simultaneously. It is important that other applications in the multifunction device do not compromise the functionality of the RAS when the device is in service or when it is being maintained. The following list outlines considerations when the RAS function is applied in the same microprocessor-based relay as equipment protection functions:

a. Describe how the multifunction device is applied in the RAS.

b. Show the general arrangement and describe how the multi-function device is labeled in the design and application, so as to identify the RAS and other device functions.

c. Describe the procedures used to isolate the RAS function from other functions in the device.

d. Describe the procedures used when each multifunction device is removed from service and whether coordination with other protection schemes is required.

e. Describe how each multifunction device is tested, both for commissioning and during periodic maintenance testing, with regard to each function of the device.

f. Describe how overall periodic RAS functional and throughput tests are performed if multifunction devices are used for both local protection and RAS.

g. Describe how upgrades to the multifunction device, such as firmware upgrades, are accomplished. How is the RAS function taken into consideration?

Other devices that are usually not considered multifunction devices such as auxiliary relays, control switches, and instrument transformers may serve multiple purposes such as protection and RAS. Similar concerns apply for these applications as noted above.

4. Documentation describing the System performance resulting from a single component failure in the RAS, except for limited impact RAS, when the RAS is intended to operate. A single component failure in a RAS not determined to be limited impact must 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 is designed. The documentation should describe or illustrate how the design achieves this objective. [Reference NERC Reliability Standard PRC-012, R1.3]

   RAS automatic arming, if applicable, is vital to RAS and System performance and is therefore included in this requirement. Acceptable methods to achieve this objective include, but are not limited to the following:

   a. Providing redundancy of RAS components. Typical examples are listed below:

      i. Protective or auxiliary relays used by the RAS.

      ii. Communications systems necessary for correct operation of the RAS.

iii. Sensing devices used to measure electrical or other quantities used by the RAS.

iv. Station dc supply associated with RAS functions.

v. Control circuitry associated with RAS functions through the trip coil(s) of the circuit breakers or other interrupting devices.

vi. Logic processing devices that accept System inputs from RAS components or other sources, make decisions based on those inputs, or initiate output signals to take remedial actions.

b. Arming more load or generation than necessary such that failure of the RAS to drop a portion of load or generation due to that single component failure will still result in satisfactory System performance, as long as tripping the total armed amount of load or generation does not cause other adverse impacts to reliability.

c. Using alternative automatic actions to back up failures of single RAS components.

d. 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.

5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies important RAS information for each existing RAS to be retired that the RAS-entity shall document and provide to the Reliability Coordinator for review pursuant to Requirement R1.

1. Information necessary to ensure that the Reliability Coordinator is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of technical studies and technical justifications, if applicable, upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

While the documentation necessary to evaluate RAS removals is not as extensive as for new or functionally modified RAS, it is still vital that, when the RAS is no longer available, System performance will still meet the appropriate (usually TPL) requirements for the Contingencies or System conditions that the RAS had been installed to remediate.

Technical Justification for Attachment 2 Content

Reliability Coordinator RAS Review Checklist

Attachment 2 is a checklist provided to facilitate consistent reviews continent-wide for new or functionally modified RAS prior to the RAS installation. The checklist is meant to assist the RC in identifying reliability-related considerations relevant to various aspects of RAS design and implementation.

Technical Justifications for Attachment 3 Content

Database Information

Attachment 3 contains the minimum information that the RC must consolidate into its database for each RAS in its area.

1. RAS name.
   - The name used to identify the RAS.
2. Each RAS-entity and contact information.
   - A reliable phone number or email address should be included to contact each RAS-entity if more information is needed.
3. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent five full calendar year (Requirement R4) evaluation date; and, date of retirement, if applicable.
   - Specify each applicable date.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery).
   - A short description of the reason for installing the RAS is sufficient, as long as the main System issues addressed by the RAS can be identified by someone with a reliability need.
5. Description of the Contingencies or System conditions for which the RAS was designed (initiating conditions).
   - A high level summary of the conditions/Contingencies is expected. Not all combinations of conditions are required to be listed.
6. Corrective action taken by the RAS.
   - A short description of the actions should be given. For schemes shedding load or generation, the maximum amount of megawatts should be included.

7. Identification of limited impact[10] RAS.
    - Specify whether or not the RAS is designated as limited impact.
8. Any additional explanation relevant to high-level understanding of the RAS.
    - If deemed necessary, any additional information can be included in this section, but is not mandatory.

[10] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

Draft 2 of PRC-012-2 corrects the applicability of the fill-in-the-blank standards (PRC-012-1, PRC-013-1, and PRC-014-1) by assigning the requirement responsibilities to the specific users, owners, and operators of the Bulk-Power System, and incorporates the reliability objectives of all the RAS~~/SPS~~-related standards. This draft contains nine requirements and measures, the associated rationale boxes and corresponding technical guidelines. There are also three attachments within the draft standard that are incorporated via references in the requirements. This draft of PRC-012-2 is posted for a 45-day formal comment period with a parallel ballot in the last ten days of the comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	February 12, 2014
SAR posted for comment	February 18, 2014
Standards Committee approved the SAR	June 10, 2014
Draft 1 of PRC-012-2 posted for informal comment	April 30 – May 20, 2015
45-day formal comment period with initial ballot	August 20 – October 5, 2015
45-day formal comment period with additional ballot	November 25, 2015 – January 8, 2016
45-day formal comment period with additional ballot	February 3, 2016 – March 18, 2016

Anticipated Actions	Date
10-day final ballot	~~March~~April 2016
NERC Board (Board) adoption	May 2016

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Remedial Action Schemes
2. **Number:** PRC-012-2
3. **Purpose:** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Planning Coordinator
     - **4.1.3.** RAS-entity – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS
   - **4.2. Facilities:**
     - **4.2.1.** Remedial Action Schemes (RAS)
5. **Effective Date:** See the Implementation Plan for PRC-012-2.

B. Requirements and Measures

Rationale for Requirement R1: Each Remedial Action Scheme (RAS) is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES). Therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification or retirement; i.e., removal from service must be completed prior to implementation or retirement.

Functional modifications consist of any of the following:

- Changes to System conditions or Contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond ~~error~~ correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

To facilitate a review that promotes reliability, the RAS-entity must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity provide them to the reviewing Reliability Coordinator (RC). The RC (reviewing RC) that coordinates the area where the RAS is located is responsible for the review. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate and submit a single, coordinated Attachment 1 to the reviewing RC. In cases where a RAS crosses ~~one or more~~ RC Area boundaries, each affected RC is responsible for conducting either individual reviews or participating in a coordinated review.

R1. Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, a copy of the Attachment 1 documentation and the dated communications with the reviewing Reliability Coordinator(s) in accordance with Requirement R1.

Rationale for Requirement R2: The RC is the functional entity best suited to perform the RAS review because it has the widest-area operational and reliability perspective of all functional entities and an awareness of reliability issues in any neighboring RC Area. This Wide Area purview facilitates the evaluation of interactions among separate RAS as well as interactions among RAS and other protection and control systems. Review by the RC also minimizes the possibility of a conflict of interest that could exist because of business relationships among the RAS-entity, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC is not expected to possess more information or ability than anticipated by their

functional registration as designated by NERC. The RC may request assistance to perform RAS reviews from other parties such as the PC or regional technical groups; however, the RC will retain the responsibility for compliance with this requirement.

Attachment 2 of this standard is a checklist the RC can use to identify design and implementation aspects of RAS and facilitate consistent reviews for each submitted RAS. The time frame of four full calendar months is consistent with current utility and regional practice; however, flexibility is provided by allowing the RC(s) and RAS-entity(ies) to negotiate a mutually agreed upon schedule for the review.

Note: An RC may need to include this task in its reliability plan(s) for the NERC Regions(s) in which it is located.

R2. Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated reports, checklists, or other documentation detailing the RAS review, and the dated communications with the RAS-entity in accordance with Requirement R2.

Rationale for Requirement R3: The RC review is intended to identify reliability issues that must be resolved before the RAS can be put in-service. Examples of reliability issues include a lack of dependability, security, or coordination.

A specific time period for the RAS-entity to respond to the reviewing RC following identification of any reliability issue(s) is not necessary because the RAS-entity wants to expedite the timely approval and subsequent implementation of the RAS.

A specific time period for the RC to respond to the RAS-entity following the RAS review is also not necessary because the RC will be aware of (1) any reliability issues associated with the RAS not being in service and (2) the RAS-entity's schedule to implement the RAS to address those reliability issues. Since the RC is the ultimate arbiter of BES operating reliability, resolving reliability issues is a priority for the RC and serves as an incentive to expeditiously respond to the RAS-entity.

R3. Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Acceptable evidence may include, but is not limited to, dated documentation and communications with the reviewing Reliability Coordinator that no reliability issues

were identified during the review or that all identified reliability issues were resolved in accordance with Requirement R3.

Rationale for Requirement R4: Requirement R4 mandates that an evaluation of each RAS be performed at least once every ~~sixty~~five full calendar ~~months~~years. The purpose of the periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that, if a RAS single component ~~failure~~malfunction or single component ~~malfunction~~failure were to occur, the requirements for BES performance would continue to be satisfied. ~~The~~A periodic evaluation is ~~needed~~required because changes in System topology or operating conditions may change the effectiveness of a RAS or the way it impacts the BES. ~~Requirement R4 also clarifies~~

RAS are unique and customized assemblages of protection and control equipment that vary in complexity and impact on the ~~RAS single component failure and single component malfunction tests do not apply to~~reliability of the BES. In recognition of these differences, RAS ~~which are determined to~~can be ~~limited impact. A RAS~~ designated by the reviewing RC(s) as limited impact. A limited impact RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. ~~A RAS implemented after the effective date of this standard will be designated as limited~~Limited impact ~~or~~RAS are not ~~by the reviewing RC(s) during its review. A RAS implemented prior~~subject to the ~~effective date of this standard that has been through the regional review process~~ RAS single component malfunction and ~~designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact for the purposes of Requirement 4,~~ failure tests of Parts 4.1.~~3~~4 and 4.1.~~4.~~5, respectively. Requiring a limited impact RAS to meet ~~the single component failure and single component malfunction~~ these tests would add complexity to the design with minimal benefit to ~~the~~BES reliability~~ of the BES~~. See ~~Attachment 2~~the Supplemental Material for ~~a description of~~more on the limited impact ~~determination by the Reliability Coordinator~~designation.

The limited impact designation is modeled after the Local Area Protection Scheme (LAPS) classification in WECC (Western Electricity Coordinating Council) and the Type 3 classification in NPCC (Northeast Power Coordinating Council). A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type 3 in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.

For existing RAS, the initial performance of Requirement R4 must be completed within ~~sixty~~five full calendar ~~months~~years of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within ~~sixty~~five full calendar ~~months~~years of the RAS approval date by the reviewing RC(s). ~~Sixty~~Five full calendar ~~months~~years was selected as the maximum time frame between evaluations based on the time frames for similar requirements in Reliability

Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation can be performed sooner if it is determined that material changes to System topology or System operating conditions could potentially impact the effectiveness or coordination of the RAS. System changes also have the potential to alter the reliability impact of limited impact RAS on the BES. Requirement 4, Part 4.1.3 explicitly requires the periodic evaluation of limited impact RAS to verify the limited impact designation remains applicable. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the ~~evaluation~~evaluations (Requirement R4, Parts 4.1.1 through 4.1.5) are planning analyses that may involve modeling of the interconnected transmission system to assess BES performance. The Planning Coordinator (PC) is the functional entity best suited to perform this evaluation because they have a wide area planning perspective. To promote reliability, the PC is required to provide the results of the evaluation to each impacted Transmission Planner and Planning Coordinator, in addition to each reviewing RC and RAS-entity. In cases where a RAS crosses PC boundaries, each affected PC is responsible for conducting either individual evaluations or participating in a coordinated evaluation.

The previous version of this standard (PRC-012-1 Requirement 1, R1.4) states "… 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." Requirement R4 clarifies that the inadvertent operation to be considered would only be that caused by the malfunction of a single RAS component. This allows security features to be designed into the RAS such that inadvertent operation due to a single component malfunction is prevented. Otherwise, consistent with PRC-012-1 Requirement 1, R1.4, the RAS should be designed so that its whole or partial inadvertent operation due to a single component malfunction satisfies the System 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 some other Contingency or System condition not defined in TPL-001-4 (therefore without performance requirements), its inadvertent operation still must meet some minimum System performance requirements. However, instead of referring to the TPL-001-4, Requirement R4 lists the System performance requirements that the inadvertent operation must satisfy. The performance requirements listed (Parts 4.1.3.1 – 4.1.3.5) are the ones that are common to all planning events P0-P7 listed in TPL-001-4.

R4. Each Planning Coordinator, at least once every ~~60~~five full calendar ~~months~~years, shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Perform an evaluation of each RAS within its planning area to determine whether:

4.1.1. The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed.

4.1.2. The RAS avoids adverse interactions with other RAS, and protection and control systems.

4.1.3. For limited impact[1] RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

~~4.1.3.~~4.1.4. Except for limited impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following:

~~4.1.3.1.~~4.1.4.1. The BES shall remain stable.

~~4.1.3.2.~~4.1.4.2. Cascading shall not occur.

~~4.1.3.3.~~4.1.4.3. Applicable Facility Ratings shall not be exceeded.

~~4.1.3.4.~~4.1.4.4. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

~~4.1.3.5.~~4.1.4.5. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

~~4.1.4.~~4.1.5. Except for limited impact RAS, 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 is designed.

4.2. Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.

M4. Acceptable evidence may include, but is not limited to, dated reports or other documentation of the analyses comprising the evaluation(s) of each RAS and dated communications with the RAS-entity(ies), Transmission Planner(s), Planning

[1] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. ~~See Attachment 2 for a description of the limited impact determination by the Reliability Coordinator. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact for the purposes of Requirement 4, Parts 4.1.3 and 4.1.4.~~

Coordinator(s), and the reviewing Reliability Coordinator(s) in accordance with Requirement R4.

Rationale for Requirement R5: The correct operation of a RAS is important for maintaining the reliability and integrity of the BES. Any incorrect operation of a RAS indicates that the RAS effectiveness and/or coordination has been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: 1) verify RAS operation was consistent with the implemented design; or 2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120 full calendar day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation. To promote reliability, each RAS-entity is required to provide the results of RAS operational performance analyses that identified any deficiencies to its reviewing RC(s).

RAS-entities may need to collaborate with their associated Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation was triggered correctly (Part 5.1.1), responded as designed (Part 5.1.2), and that the resulting BES response (Parts 5.1.3 and 5.1.4) was consistent with the intended functionality and design of the RAS. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate ~~on the~~to conduct and submit a single, coordinated operational performance analysis.

R5. Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Participate in analyzing the RAS operational performance to determine whether:

5.1.1. The System events and/or conditions appropriately triggered the RAS.

5.1.2. The RAS responded as designed.

5.1.3. The RAS was effective in mitigating BES performance issues it was designed to address.

5.1.4. The RAS operation resulted in any unintended or adverse BES response.

5.2. Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).

M5. Acceptable evidence may include, but is not limited to, dated documentation detailing the results of the RAS operational performance analysis and dated communications with participating RAS-entities and the reviewing Reliability Coordinator(s) in accordance with Requirement R5.

Rationale for Requirement R6: Deficiencies identified in the periodic RAS evaluation conducted by the PC pursuant to Requirement R4, in the operational performance analysis conducted by the RAS-entity pursuant to Requirement R5, or in the functional test performed by the RAS-entity pursuant to Requirement R8, potentially pose a reliability risk to the BES. To mitigate these potential reliability risks, Requirement R6 mandates that each RAS-entity develop a Corrective Action Plan (CAP) to address the identified deficiency. The CAP contains the mitigation actions and associated timetable necessary to remedy the specific deficiency. The RAS-entity may request assistance with CAP development from other parties such as its Transmission Planner or Planning Coordinator; however, the RAS-entity has the responsibility for compliance with this requirement.

If the CAP requires that a functional change be made to a RAS, the RAS-entity will need to submit information identified in Attachment 1 to the reviewing RC(s) prior to placing RAS modifications in-service per Requirement R1.

Depending on the complexity of the identified deficiency(ies), development of a CAP may require studies, and other engineering or consulting work. A maximum time frame of six full calendar months is specified for RAS-entity collaboration on the CAP development. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to develop and submit a single, coordinated CAP.

R6. Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

- Being notified of a deficiency in its RAS pursuant to Requirement R4, or
- Notifying the Reliability Coordinator of a deficiency pursuant to Requirement~~s~~ R5, Part 5.2, or
- Identifying a deficiency in its RAS pursuant to Requirement R8.

M6. Acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each reviewing Reliability Coordinator and each RAS-entity in accordance with Requirement R6.

Rationale for Requirement R7: Requirement R7 mandates each RAS-entity implement a CAP (developed in Requirement R6) that mitigates the deficiencies identified in Requirements R4, R5, or R8. By definition, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem." The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. Each reviewing Reliability Coordinator must be notified if CAP actions or timetables change, and when the CAP is completed.

R7. Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

7.1. Implement the CAP.

7.2. Update the CAP if actions or timetables change.

7.3. Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

M7. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, and communication with the reviewing Reliability Coordinator(s) that documents the implementation, updating, or completion of a CAP in accordance with Requirement R7.

Rationale for Requirement R8: Due to the wide variety of RAS designs and implementations, and the potential for impacting BES reliability, it is important that periodic functional testing of a RAS be performed. A functional test provides an overall confirmation of the RAS to operate as designed and verifies the proper operation of the non-Protection System (control) components of a RAS that are not addressed in PRC-005. Protection System components that are part of a RAS are maintained in accordance with PRC-005.

The six or twelve full calendar year test interval, which begins on the effective date of the standard pursuant to the PRC-012-2 implementation plan, is a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS. Extending to longer intervals increases the reliability risk to the BES posed by an undiscovered latent failure that could cause an incorrect operation or failure of the RAS. The RAS-entity is in the best position to determine the testing procedure and schedule due to its overall knowledge of the RAS design, installation, and functionality. Functional testing may be accomplished with end-to-end testing or a segmented approach. For segmented testing, each segment of a RAS must be tested. Overlapping segments can be tested individually negating the need for complex maintenance schedules and outages.

The maximum allowable interval between functional tests is six full calendar years for RAS that are not designated as limited impact RAS and twelve full calendar years for RAS that are designated as limited impact RAS. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. A correct operation of a RAS qualifies as a functional test for those RAS segments which operate (documentation for compliance with Requirement R5 Part 5.1). If an event causes a partial operation of a RAS, the segments without an operation will require a separate functional test within the maximum interval with the starting date determined by the previous successful test of the segments that did not operate.

R8. Each RAS-entity shall participate in performing a functional test of each of its RAS to verify the overall RAS performance and the proper operation of non-Protection System components: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

- At least once every six full calendar years for all RAS not designated as limited impact, or
- At least once every twelve full calendar years for all RAS designated as limited impact

M8. Acceptable evidence may include, but is not limited to, dated documentation detailing the RAS operational performance analysis for a correct RAS segment or an end-to-end operation (Measure M5 documentation), or dated documentation demonstrating that a functional test of each RAS segment or an end-to-end test was performed in accordance with Requirement R8.

Rationale for Requirement R9: The RAS database is a comprehensive record of all RAS existing in a Reliability Coordinator Area. The database enables the RC to provide other entities high-level information on existing RAS that could potentially impact the operational and/or planning activities of that entity. Attachment 3 lists the minimum information required for the RAS database, which includes a summary of the RAS initiating conditions, corrective actions, and System issues being mitigated. This information allows an entity to evaluate the reliability need for requesting more detailed information from the RAS-entities identified in the database contact information. The RC is the appropriate entity to maintain the database because the RC receives the required database information when a new or modified RAS is submitted for review. The twelve full calendar month time frame is aligned with industry practice and allows sufficient time for the RC to collect the appropriate information from RAS-entities and update the RAS database.

R9. Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once every twelve full calendar months. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M9. Acceptable evidence may include, but is not limited to, dated spreadsheets, database reports, or other documentation demonstrating a RAS database was updated in accordance with Requirement R9.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The RAS-entity (Transmission Owner, Generator Owner, and Distribution Provider) shall each keep data or evidence to show compliance with Requirements R1, R3, R5, R6, R7, and R8, and Measures M1, M3, M5, M6, M7, and M8 since the last audit, unless directed by its Compliance Enforcement

Authority to retain specific evidence for a longer period of time as part of an investigation.

The Reliability Coordinator shall each keep data or evidence to show compliance with Requirements R2 and R9, and Measures M2 and M9 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Planning Coordinator shall each keep data or evidence to show compliance with Requirement R4 and Measure M4 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a RAS-entity (Transmission Owner, Generator Owner or Distribution Provider), Reliability Coordinator, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The RAS-entity failed to provide the information identified in Attachment 1 to each Reliability Coordinator prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R1.
R2.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90 full calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in accordance with Requirement R2.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	N/A	N/A	N/A	The RAS-entity failed to resolve identified reliability issue(s) to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R3.
R4.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but ~~in greater than 60 full calendar months but~~was late by less than or equal to ~~61~~30 full calendar ~~months~~days.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but ~~in greater~~was late by more than ~~61~~30 full calendar ~~months~~days but less than or equal to ~~62~~60 full~~-~~ calendar ~~months~~days.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but ~~in greater~~was late by more than ~~62~~60 full calendar ~~months~~days but less than or equal to ~~63~~90 full calendar ~~months~~days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but ~~in greater~~was late by more than ~~63~~90 full calendar ~~months~~days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate two or more of the Parts 4.1.1 through 4.1.~~4~~5.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			to evaluate one of the Parts 4.1.1 through 4.1.~~4~~5.	OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to provide the results to one or more of the receiving entities listed in Part 4.2. OR The Planning Coordinator failed to perform the evaluation in accordance with Requirement R4.
R5.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by less than or equal to 10 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address two or

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			failed to address one of the Parts 5.1.1 through 5.1.4.	more of the Parts 5.1.1 through 5.1.4. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to provide the results (Part 5.2) to one or more of the reviewing Reliability Coordinator(s). OR The RAS-entity failed to perform the analysis in accordance with Requirement R5.
R6.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30 full calendar days. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The RAS-entity developed a Corrective Action Plan but failed to submit it to one or more of its reviewing Reliability Coordinator(s) in accordance with Requirement R6. OR The RAS-entity failed to develop a Corrective Action Plan in accordance with Requirement R6.
R7.	The RAS-entity implemented a CAP in accordance with Requirement R7, Part 7.1, but failed to update the CAP (Part 7.2) if actions or timetables changed, or failed to notify (Part 7.3) each of the reviewing Reliability Coordinator(s) of the updated CAP or completion of the CAP.	N/A	N/A	The RAS-entity failed to implement a CAP in accordance with Requirement R7, Part 7.1.
R8.	The RAS-entity performed the functional test for a RAS as specified in Requirement	The RAS-entity performed the functional test for a RAS as specified in Requirement	The RAS-entity performed the functional test for a RAS as specified in Requirement	The RAS-entity performed the functional test for a RAS as specified in Requirement

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	R8, but was late by less than or equal to 30 full calendar days.	R8, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	R8, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	R8, but was late by more than 90 full calendar days. OR The RAS-entity failed to perform the functional test for a RAS as specified in Requirement R8.
R9.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90 full calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

D. Regional Variances

None.

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
1		Adopted by NERC Board of Trustees	New

Attachment 1
Supporting Documentation for RAS Review

The following checklist identifies important Remedial Action Scheme (RAS) information for each new or functionally modified[2] RAS that the RAS-entity must document and provide to the reviewing Reliability Coordinator(s) (RC). If an item on this list does not apply to a specific RAS, a response of "Not Applicable" for that item is appropriate. When RAS are submitted for functional modification review and approval, only the proposed modifications to that RAS require review; however, the RAS-entity must provide a summary of the existing functionality. The RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS. Additional entities (without decision authority) may be part of the RAS review process at the request of the RC.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.
2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.
3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP.
4. Data to populate the RAS database:
    a. RAS name.
    b. Each RAS-entity and contact information.
    c. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
    d. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
    e. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
    f. Action(s) to be taken by the RAS.

[2] Functionally Modified: Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond ~~error~~ correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

g. Identification of limited impact[3] RAS.

h. Any additional explanation relevant to high-level understanding of the RAS.

II. Functional Description and Transmission Planning Information

1. Contingencies and System conditions that the RAS is intended to remedy.
2. The action(s) to be taken by the RAS in response to disturbance conditions.
3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and the date those technical studies were performed.
4. Information regarding any future System plans that will impact the RAS.
5. RAS-entity ~~proposed designation as~~proposal and justification for limited impact ~~or not~~designation, if applicable.
6. Documentation describing the System performance resulting from the possible inadvertent operation of the RAS, except for limited impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be limited impact must satisfy all of the following:
   a. The BES shall remain stable.
   b. Cascading shall not occur.
   c. Applicable Facility Ratings shall not be exceeded.
   d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.
   e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.
7. An evaluation indicating that the RAS settings and operation avoid adverse interactions with other RAS, and protection and control systems.
8. Identification of other affected RCs.

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[3] A RAS designated as ~~"~~limited impact~~"~~ cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. ~~See Attachment 2 for a description of the limited impact determination by the Reliability Coordinator. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.~~

III. Implementation

1. Documentation describing the applicable equipment used for detection, dc supply, communications, transfer trip, ~~control actions,~~ logic processing, control actions, and monitoring.
2. Information on detection logic and settings/parameters that control the operation of the RAS.
3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in-service or is being maintained.
4. Documentation describing the System performance resulting from a single component failure in the RAS, except for limited impact RAS, when the RAS is intended to operate. A single component failure in a RAS not determined to be limited impact must 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 is designed. The documentation should describe or illustrate how the design achieves this objective.
5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies RAS information that the RAS-entity shall document and provide to each reviewing RC.

1. Information necessary to ensure that the RC is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of applicable technical studies and technical justifications upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

Attachment 2
Reliability Coordinator RAS Review Checklist

The following checklist identifies reliability-related considerations for the Reliability Coordinator (RC) to review and verify for each new or functionally modified[4] Remedial Action Scheme (RAS). The RC review is not limited to the checklist items and the RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS. If a checklist item is not relevant to a particular RAS, it should be noted as “Not Applicable.” If reliability considerations are identified during the review, the considerations and the proposed resolutions should be documented with the remaining applicable Attachment 2 items.

I. Design

1. The RAS actions satisfy performance objectives for the scope of events and conditions that the RAS is intended to mitigate.

2. The designed timing of RAS operation(s) is appropriate to its BES performance objectives.

~~2.~~3. The RAS arming conditions, if applicable, are appropriate to its System performance objectives.

~~3.~~4. The RAS avoids adverse interactions with other RAS, and protection and control systems.

~~4.~~5. The effects of RAS incorrect operation, including inadvertent operation and failure to operate, have been identified.

~~5.~~6. Determination whether or not the RAS is ~~“~~limited impact.[5]~~”~~ A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

~~6.~~7. Except for limited impact RAS as determined by the RC, the possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following:

   a. The BES shall remain stable.

   b. Cascading shall not occur.

   c. Applicable Facility Ratings shall not be exceeded.

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[4] Functionally Modified: Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond ~~error~~ correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

[5] A RAS designated as ~~“~~limited impact~~”~~ cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. ~~A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.~~

d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

~~7.~~8. The effects of future BES modifications on the design and operation of the RAS have been identified, where applicable.

II. Implementation

1. The implementation of RAS logic appropriately correlates desired actions (outputs) with events and conditions (inputs).

~~2. The timing of RAS action(s) is appropriate to its BES performance objectives.~~

~~3.~~2. Except for limited impact RAS as determined by the RC, a single component failure in a RAS does not prevent the BES from meeting the same performance requirements as those required for the events and conditions for which the RAS is designed.

~~4.~~3. The RAS design facilitates periodic testing and maintenance.

~~5.~~4. The mechanism or procedure by which the RAS is armed is clearly described, and is appropriate for reliable arming and operation of the RAS for the conditions and events for which it is designed to operate.

III. RAS Retirement

RAS retirement reviews should assure that there is adequate justification for why a RAS is no longer needed.

Attachment 3
Database Information

1. RAS name.
2. Each RAS-entity and contact information.
3. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
5. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
6. Action(s) to be taken by the RAS.
7. Identification of limited impact[6] RAS.
8. Any additional explanation relevant to high-level understanding of the RAS.

[6] A RAS designated as ~~"~~limited impact~~"~~ cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. ~~A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.~~

Technical ~~Justifications for Requirements~~Justification

~~Applicability~~

4.1.1 Reliability Coordinator

The Reliability Coordinator (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. The Wide-Area purview 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, Planning Coordinator, Transmission Planner, or other entities 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.

4.1.2 Planning Coordinator

The Planning Coordinator (PC) is the best-suited functional entity to perform the RAS evaluation 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, similar to the planning analyses performed by PCs.

4.1.3 RAS-entity

The RAS-entity is any Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If all of the RAS (RAS components) have a single owner, then that RAS-entity has sole responsibility for all the activities assigned within the standard to the RAS-entity. If the RAS (RAS components) have more than one owner, then each separate RAS component owner is a RAS-entity and is obligated to participate in various activities identified by the Requirements.

The standard does not stipulate particular compliance methods. RAS-entities have the option of collaborating to fulfill their responsibilities for each applicable requirement. Such collaboration and coordination may promote efficiency in achieving the reliability objectives of the requirements; however, the individual RAS-entity must be able to demonstrate its participation for compliance. As an example, the individual RAS-entities could collaborate to produce and submit a single, coordinated Attachment 1 to the reviewing RC pursuant to Requirement R1 to initiate the RAS review process.

Limited impact

RAS are unique and customized assemblages of protection and control equipment that vary in complexity and impact on the reliability of the BES. These differences in RAS design, action, and risk to the BES are identified and verified within the construct of Requirements R1-R4 of PRC-012-2.

The reviewing RC has the authority to designate a RAS as limited impact if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. The reviewing RC is the sole arbiter for determining whether a RAS qualifies for the limited impact designation. The limited impact designation is available to any RAS in any Region provided the reviewing RC determines the RAS poses a low risk to BES reliability.

The limited impact designation is modeled after the Local Area Protection Scheme (LAPS) classification in WECC (Western Electricity Coordinating Council) and the Type 3 classification in NPCC (Northeast Power Coordinating Council). The following information describing the aforementioned WECC and NPCC RAS is excerpted from the respective regional documentation[7].The drafting team notes that the information below represents the state of the WECC and NPCC regional processes at the time of this standard development and is subject to change before the effective date of PRC-012-2.

WECC: Local Area Protection Scheme (LAPS)

A Remedial Action Scheme (RAS) whose failure to operate would NOT result in any of the following:

- Violations of TPL-001-WECC-RBP System Performance RBP,
- Maximum load loss ≥ 300 MW,
- Maximum generation loss ≥ 1000 MW.

NPCC: Type III

An SPS whose misoperation or failure to operate results in no **significant adverse impact** outside the **local area**.

The following terms are also defined by NPCC to assess the impact of the SPS for classification:

Significant adverse impact – With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from faults or disturbances, shall be deemed as having significant adverse impact:

a. system instability;
b. unacceptable system dynamic response or equipment tripping;
c. voltage levels in violation of applicable emergency limits;
d. loadings on transmission facilities in violation of applicable emergency limits;
e. unacceptable loss of load.

Local area – An electrically confined or radial portion of the system. The geographic size and number of system elements contained will vary based on system characteristics. A local area may be relatively large geographically with relatively few buses in a sparse system, or be

[7] WECC Procedure to Submit a RAS for Assessment Information Required to Assess the Reliability of a RAS Guideline, Revised 10/28/2013 | NPCC Regional Reliability Reference Directory # 7, Special Protection Systems, Version 2, 3/31/2015

relatively small geographically with a relatively large number of buses in a densely networked system.

Because the drafting team modeled the limited impact designation after the WECC and NPCC classifications, each RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type 3 in NPCC, is recognized as a limited impact RAS upon the effective date of PRC-012-2 and is subject to all applicable requirements.

To propose an existing RAS (a RAS implemented prior to the effective date of PRC-012-2) be designated as limited impact by the reviewing RC, the RAS-entity must prepare and submit the appropriate Attachment 1 information that includes the technical justification (evaluations) documenting that the System can meet the performance requirements (specified in Requirement R4, Parts 4.1.4 and 4.1.5) resulting from a single RAS component malfunction or failure, respectively.

There is nothing that precludes a RAS-entity from working with the reviewing RC during the implementation period of PRC-012-2, in anticipation of the standard becoming enforceable. However, even if the reviewing RC determines the RAS qualifies as limited impact, the designation is not relevant until the standard becomes effective. Until then, the existing regional processes remain in effect as well as the existing RAS classifications or lack thereof.

An example of a scheme that could be recognized as a limited impact RAS is a load shedding or generation rejection scheme used to mitigate the overload of a BES transmission line. The inadvertent operation of such a scheme would cause the loss of either a certain amount of generation or load. The evaluation by the RAS-entity should demonstrate that the loss of this amount of generation or load, without the associated contingency for RAS operation actually occurring, is acceptable and not detrimental to the reliability of BES; e.g., in terms of frequency and voltage stability. The failure of that scheme to operate when intended could potentially lead to the overloading of a transmission line beyond its acceptable rating. The RAS-entity would need to demonstrate that this overload, while in excess of the applicable Facility Rating, is not detrimental to the BES outside the contained area (predetermined by studies) affected by the contingency.

Another example of a limited-impact RAS is a scheme used to protect BES equipment from damage caused by overvoltage through generation rejection or equipment tripping.

Another example of a limited-impact RAS is a centrally-controlled undervoltage load shedding scheme used to protect a contained area (predetermined by studies) of the BES against voltage collapse.

Requirement R1

Each RAS is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES); therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification, or retirement (removal from service) must be completed prior to implementation.

Functional modifications consists of any of the following:

- Changes to System conditions or Contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond ~~error~~ correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

An example indicating the limits of an in-kind replacement of a RAS component is the replacement of one relay (or other device) with a relay (or other device) that uses similar functions. For instance, if a RAS included a CO-11 relay which was replaced by an IAC-53 relay, that would be an in-kind replacement. If the CO-11 relay were replaced by a microprocessor SEL-451 relay that used only the same functions as the original CO-11 relay, that would also be an in-kind replacement; however, if the SEL-451 relay was used to add new logic to what the CO-11 relay had provided, then the replacement relay would be a functional modification.

Changes to RAS pickup levels that require no other scheme changes are not considered a functional modification. For example, System conditions require a RAS to be armed when the combined flow on two lines exceeds 500 MW. If a periodic evaluation pursuant to Requirement R4, or other assessment, indicates that the arming level should be reduced to 450 MW without requiring any other RAS changes that would not be a functional modification. Similarly, if a RAS is designed to shed load to reduce loading on a particular line below 1000 amps, then a change in the load shedding trigger from 1000 amps to 1100 amps would not be a functional modification.

Another example illustrates a case where a System change may result in a RAS functional change. Assume that a generation center is connected to a load center through two transmission lines. The lines are not rated to accommodate full plant output if one line is out of service, so a RAS monitors the status of both lines and trips or ramps down the generation to a safe level following loss of either line. Later, one of the lines is tapped to serve additional load. The System that the RAS impacts now includes three lines, loss of any of which is likely to still require generation reduction. The modified RAS will need to monitor all three lines (add two line terminal status inputs to the RAS) and the logic to recognize the specific line outages would change, while the generation reduction (RAS output) requirement may or may not change, depending on which line is out of service. These required RAS changes would be a functional modification.

Any functional modification to a RAS will need to be reviewed and approved through the process described in Requirements R1, R2, and R3. The need for such functional modifications may be identified in several ways including but not limited to the Planning evaluations pursuant to R4, incorrect operations pursuant to R5, a test failure pursuant to R8, or Planning assessments related to future additions or modifications of other facilities.

To facilitate a review that promotes reliability, the RAS-entity(ies) must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity(ies) provide them to the reviewing Reliability Coordinator (RC). The RC that coordinates the area where the RAS is located is responsible for the review. In cases where a RAS crosses multiple RC Area boundaries, each affected RC is responsible for conducting either individual reviews or a coordinated review.

Requirement R1 does not specify how far in advance of implementation the RAS-entity(ies) must provide Attachment 1 data to the reviewing RC. The information will need to be submitted early enough to allow RC review in the allotted time pursuant to Requirement R2, including resolution of any reliability issues that might be identified, in order to obtain approval of the reviewing RC. Expeditious submittal of this information is in the interest of each RAS-entity to effect a timely implementation.

Requirement R2

Requirement R2 mandates that the RC perform reviews of all proposed new RAS and existing RAS proposed for functional modification, or retirement (removal from service) in its RC Area.

RAS are unique and customized assemblages of protection and control equipment. As such, they have a potential to introduce reliability risks to the BES, if not carefully planned, designed, and installed. A RAS may be installed to address a reliability issue, or achieve an economic or operational advantage, and could introduce reliability risks that might not be apparent to a RAS-entity(ies). An independent review by a multi-disciplinary panel of subject matter experts with planning, operations, protection, telecommunications, and equipment expertise is an effective means of identifying risks and recommending RAS modifications when necessary.

The RC is the functional entity best suited to perform the RAS reviews because it has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. This Wide Area purview facilitates the evaluation of interactions among separate RAS as well as interactions among the 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, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC may request assistance in RAS reviews from other parties such as the PC(s) or regional technical groups (e.g., Regional Entities); however, the RC retains responsibility for compliance with the requirement. It is recognized that the RC does not possesses more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not contain compliance requirements. If Reliability Standards address functions that are not described in the model, the Reliability Standard requirements take precedence over the Functional Model. For further reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

Attachment 2 of this standard is a checklist for assisting the RC in identifying design and implementation aspects of a RAS, and for facilitating consistent reviews of each RAS submitted for review. The time frame of four full calendar months is consistent with current utility practice; however, flexibility is provided by allowing the parties to negotiate a different schedule for the review. Note, an RC may need to include this task in its reliability plan(s) for the NERC Region(s) in which it is located.

Requirement R3

Requirement R3 mandates that each RAS-entity resolve all reliability issues (pertaining to its RAS) identified during the RAS review by the reviewing Reliability Coordinators. Examples of reliability issues include a lack of dependability, security, or coordination. RC approval of a RAS is considered to be obtained when the reviewing RC's feedback to each RAS-entity indicates that either no reliability issues were identified during the review or all identified reliability issues were resolved to the RC's satisfaction.

Dependability is a component of reliability that is the measure of certainty of a device to operate when required. If a RAS is installed to meet performance requirements of NERC Reliability Standards, a failure of the RAS to operate when intended would put the System at risk of violating NERC Reliability Standards if specified Contingency(ies) or System conditions occur. This risk is mitigated by designing the RAS so that it will accomplish the intended purpose while experiencing a single RAS component failure. This is often accomplished through redundancy. Other strategies for providing dependability include "over-tripping" load or generation, or alternative automatic backup schemes.

Security is a component of reliability that is the measure of certainty of a device to not operate inadvertently. False or inadvertent operation of a RAS results in taking a programmed action without the appropriate arming conditions, occurrence of specified Contingency(ies), or System conditions expected to trigger the RAS action. Typical RAS actions include shedding load or generation or re-configuring the System. Such actions, if inadvertently taken, are undesirable and may put the System in a less secure state. Worst case impacts from inadvertent operation often occur if all programmed RAS actions occur. If the System performance still satisfies PRC-012-2 Requirement R4, Part 4.3, no additional mitigation is required. Security enhancements to the RAS design, such as voting schemes, are acceptable mitigations against inadvertent operations.

Any reliability issue identified during the review must be resolved before implementing the RAS to avoid placing the System at unacceptable risk. The RAS-entity or the reviewing RC(s) may have alternative ideas or methods available to resolve the issue(s). In either case, the concern needs to be resolved in deference to reliability, and the RC has the final decision.

A specific time period for the RAS-entity to respond to the RC(s) review is not necessary because an expeditious response is in the interest of each RAS-entity to effect a timely implementation.

A specific time period for the RC to respond to the RAS-entity following the RAS review is also not necessary because the RC will be aware of (1) any reliability issues associated with the RAS not being in service and (2) the RAS-entity's schedule to implement the RAS to address those reliability issues. Since the RC is the ultimate arbiter of BES operating reliability, resolving reliability issues is a priority for the RC and serves as an incentive to expeditiously respond to the RAS-entity.

Requirement R4

Requirement R4 mandates that an evaluation of each RAS be performed at least once every ~~60~~five full calendar ~~months~~years. The purpose of a periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that requirements for BES performance following inadvertent RAS operation and single component failure continue to be satisfied. A periodic evaluation is required because changes in System topology or operating conditions may change the effectiveness of a RAS or the way it interacts with and impacts the BES.

A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. Limited impact RAS are not subject to the RAS single component malfunction and failure tests of Parts 4.1.4 and 4.1.5, respectively. Requiring a limited impact RAS to meet these tests would add complexity to the design with minimal benefit to BES reliability.

A RAS implemented after the effective date of this standard can only be designated as limited impact by the reviewing RC(s). A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type 3 in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.

Requirement R4 also clarifies that the RAS single component failure and inadvertent operation tests do not apply to RAS which are determined to be limited impact. Requiring a limited impact RAS to meet the single component failure and inadvertent operation tests would just add complexity to the design with little or no improvement in the reliability of the BES.

For existing RAS, the initial performance of Requirement R4 must be completed within ~~sixty~~five full calendar ~~months~~years of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within ~~sixty~~five full calendar ~~months~~years of the RAS approval date by the reviewing RC(s). ~~Sixty~~Five full calendar ~~months~~years was selected as the maximum time frame between evaluations based on the time frames for similar requirements in Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation can be performed sooner if it is determined that material changes to System topology or System operating conditions could potentially impact the effectiveness or coordination of the RAS. System changes also have the potential to alter the reliability impact of limited impact RAS on the BES. Requirement 4, Part 4.1.3 explicitly requires the periodic evaluation of limited impact RAS to verify the limited impact designation remains applicable. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluations (Requirement R4, Parts 4.1.1 through 4.1.~~4~~5) are planning analyses that may involve modeling of the interconnected transmission system to assess BES performance. The PC is the functional entity best suited to perform the analyses because they have a wide-area planning perspective. To promote reliability, the PC is required to provide the results of the evaluation to each ~~RAS-entity and reviewing RC, as well as each impacted Planning Coordinator and Transmission Planner~~impacted Transmission Planner and Planning Coordinator, in addition to each reviewing RC and RAS-entity. In cases where a RAS crosses PC boundaries, each affected PC is responsible for conducting either individual evaluations or participating in a coordinated evaluation.

The intent of Requirement R4, Part 4.1.~~3~~4 is to require that the possible inadvertent operation of the RAS (other than limited impact RAS), caused by the malfunction of a single component of the RAS, meet the same System performance requirements as those required for the Contingency(ies) or System conditions for which it is designed. If the RAS is designed to meet one of the planning events (P0-P7) in TPL-001-4, the possible inadvertent operation of the RAS must meet the same performance requirements listed in the standard for that planning event. The requirement clarifies that the inadvertent operation to be considered is only that caused by the malfunction of a single RAS component. This allows features to be designed into the RAS to improve security, such that inadvertent operation due to malfunction of a single component is prevented; otherwise, the RAS inadvertent operation must satisfy Requirement R4, Part 4.1.~~3~~4.

The intent of Requirement R4, Part 4.1.~~3~~4 is also to require that the possible inadvertent operation of the RAS (other than limited impact RAS) installed for an extreme event in TPL-001-4 or for some other Contingency or System conditions not defined in TPL-001-4 (therefore without performance requirements), meet the minimum System performance requirements of Category P7 in Table 1 of NERC Reliability Standard TPL-001-4. However, instead of referring to the TPL standard, the requirement lists the System performance requirements that a potential inadvertent operation must satisfy. The performance requirements listed (Requirement R4, Parts 4.1.~~3~~4.1 – 4.1.~~3~~4.5) are the ones that are common to all planning events (P0-P7) listed in TPL-001-4.

With reference to Requirement 4, Part 4.1.~~3~~4, note that the only differences in performance requirements among the TPL (P0-P7) events (not common to all of them) concern Non-Consequential Load Loss and interruption of Firm Transmission Service. It is not necessary for Requirement R4, Part 4.1.~~3~~4 to specify performance requirements related to these areas because a RAS is only allowed to drop non-consequential load or interrupt Firm Transmission Service if that action is allowed for the Contingency for which it is designed. Therefore, the inadvertent operation should automatically meet Non-Consequential Load Loss or interrupting Firm Transmission Service performance requirements for the Contingency(ies) for which it was designed.

Part 4.1.~~4~~5 requires that a single component failure in the RAS (other than limited impact 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 is designed. This analysis is needed to ensure that changing System conditions do not result in the single component failure requirement not being met.

Requirements for inadvertent RAS operation (Requirement R4, Part 4.1.~~3~~4) and single component failure (Requirement R4, Part 4.1.~~4~~5) are reviewed by the reviewing RC(s) before a new or functionally modified RAS is placed in-service, and are typically satisfied by specific design considerations. Although the scope of the periodic evaluation does not include a new design review, it is possible that a design which previously satisfied requirements for inadvertent RAS operation and single component failure may fail to satisfy these requirements at a later time, and must be evaluated with respect to the current System. For example, if the actions of a particular RAS include tripping load, load growth could occur over time that impacts the amount of load to be tripped. These changes could result in tripping too much load upon inadvertent operation and result in violations of Facility Ratings. Alternatively, the RAS might be designed to trip more load than necessary (i.e., "over trip") in order to satisfy single component failure requirements. System changes could result in too little load being tripped and unacceptable BES performance if one of the loads failed to trip.

Requirement R5

The correct operation of a RAS is important to maintain the reliability and integrity of the BES. Any incorrect operation of a RAS indicates the RAS effectiveness and/or coordination may have been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: (1) verify RAS operation is consistent with implemented design; or (2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120 full calendar day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation; however, flexibility is provided by allowing the parties to negotiate a different schedule for the analysis. To promote reliability, the RAS-entity(s) is required to provide the results of RAS operational performance analyses to its reviewing RC(s~~).~~) if the analyses revealed a deficiency.

The RAS-entity(ies) may need to collaborate with its associated Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation was triggered correctly (Part 5.1.1), responded as designed (Part 5.1.2), and that the resulting BES response (Parts 5.1.3 and 5.1.4) was consistent with the intended functionality and design of the RAS. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate ~~on the~~to conduct and submit a single, coordinated operational performance analysis.

Requirement R6

RAS deficiencies potentially pose a reliability risk to the BES. RAS deficiencies may be identified in the periodic RAS evaluation conducted by the PC in Requirement R4, in the operational analysis conducted by the RAS-entity in Requirement R5, or in the functional test performed by the RAS-entity(ies) in Requirement R8. To mitigate potential reliability risks, Requirement R6 mandates that each RAS-entity participate in developing a CAP that establishes the mitigation actions and timetable necessary to address the deficiency.

The RAS-entity(ies) that owns the RAS components, is responsible for the RAS equipment, and is in the best position to develop the timelines and perform the necessary work to correct RAS deficiencies. If necessary, the RAS-entity(ies) may request assistance with development of the CAP from other parties such as its Transmission Planner or Planning Coordinator; however, the RAS-entity has the responsibility for compliance with this requirement.

A CAP may require functional changes be made to a RAS. In this case, Attachment 1 information must be submitted to the reviewing RC(s), an RC review must be performed to obtain RC approval before the RAS-entity can place RAS modifications in-service, per Requirements R1, R2, and R3.

Depending on the complexity of the issues, development of a CAP may require study, engineering or consulting work. A timeframe of six full calendar months is allotted to allow enough time for RAS-entity collaboration on the CAP development, while ensuring that deficiencies are addressed in a reasonable time. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to develop and submit a single, coordinated CAP. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the RAS deficiency is resolved. The possibility of such operating restrictions will incent the RAS-entity to resolve the issue as quickly as possible.

The following are example situations of when a CAP is required:

- A determination after a RAS operation/non-operation investigation that the RAS did not meet performance expectations or did not operate as designed.
- Periodic planning assessment reveals RAS changes are necessary to correct performance or coordination issues.
- Equipment failures.
- Functional testing identifies that a RAS is not operating as designed.

Requirement R7

Requirement R7 mandates that each RAS-entity implement its CAP developed in Requirement R6 which mitigates the deficiencies identified in Requirements R4, R5, or R8. By definition, a CAP is: “A list of actions and an associated timetable for implementation to remedy a specific problem.”

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. If the CAP is changed, the RAS-entity must notify the reviewing Reliability Coordinator(s). The RAS-entity must also notify the Reliability Coordinator(s) when the CAP has been completed.

The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions will incent the RAS-entity to complete the CAP as quickly as possible.

Requirement R8

The reliability objective of Requirement R8 is to test the non-Protection System components of a RAS (controllers such as programmable logic controllers (PLCs)) and to verify the overall performance of the RAS through functional testing. Functional tests validate RAS operation by ensuring System states are detected and processed, and that actions taken by the controls are correct and occur within the expected time using the in-service settings and logic. Functional testing is aimed at assuring overall RAS performance and not the component focused testing contained in the PRC-005 maintenance standard.

Since the functional test operates the RAS under controlled conditions with known System states and expected results, testing and analysis can be performed with minimum impact to the BES and should align with expected results. The RAS-entity is in the best position to determine the testing procedure and schedule due to their overall knowledge of the RAS design, installation, and functionality. Periodic testing provides the RAS-entity assurance that latent failures may be identified and also promotes identification of changes in the System that may have introduced latent failures.

The six and twelve full calendar year functional testing intervals are greater than the annual or bi-annual periodic testing performed in some NERC Regions. However, these intervals are a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS. Longer test intervals for limited impact RAS are acceptable because incorrect operations or failures to operate present a low reliability risk to the Bulk Power System.

Functional testing is not synonymous with end-to-end testing. End-to-end testing is an acceptable method but may not be feasible for many RAS. When end-to-end testing is not possible, a RAS-entity may use a segmented functional testing approach. The segments can be tested individually negating the need for complex maintenance schedules. In addition, actual RAS operation(s) can be used to fulfill the functional testing requirement. If a RAS does not operate in its entirety during a System event or System conditions do not allow an end-to-end scheme test, then the segmented approach should be used to fulfill this Requirement. Functional testing includes the testing of all RAS inputs used for detection, arming, operating, and data collection. Functional testing ~~also includes~~, by default operates the processing logic and infrastructure of a RAS, but focuses on the RAS inputs as well as the ~~action initiation~~actions initiated by RAS outputs to address the System condition(s) for which the RAS is designed. All segments and components of a RAS must be tested or have proven operations within the applicable maximum test interval to demonstrate compliance with the Requirement.

As an example of segment testing, consider a RAS controller implemented using a PLC that receives System data, such as loading or line status, from distributed devices. These distributed devices could include meters, protective relays, or other PLCs. In this example RAS, a line protective relay is used to provide an analog metering quantity to the RAS control PLC. A functional test would verify that the System data is received from the protective relay by the PLC, processed by the PLC, and that PLC outputs are appropriate. There is no need to verify the protective relay's ability to measure the power system quantities, as this is a requirement for Protection Systems used as RAS in PRC-005, Table 1-1, Component Type – Protective Relay. Rather the functional test is focused on the use of the protective relay data at the PLC, including the communications data path from relay to PLC if this data is essential for proper RAS operation. Additionally, if the control signal back to the protective relay is also critical to the proper functioning of this example RAS, then that path is also verified up-to the protective relay. This example describes a test for one segment of a RAS which verifies RAS action, verifies PLC control logic, and verifies RAS communications.

IEEE C37.233, "IEEE Guide for Power System Protection Testing," 2009 section 8 (particularly 8.3-8.5), provides an overview of functional testing. The following opens section 8.3:

> Proper implementation requires a well-defined and coordinated test plan for performance evaluation of the overall system during agreed maintenance intervals. The maintenance test plan, also referred to as functional system testing, should include inputs, outputs, communication, logic, and throughput timing tests. The functional tests are generally not component-level testing, rather overall system testing. Some of the input tests may need to be done ahead of overall system testing to the extent that the tests affect the overall performance. The test coordinator or coordinators need to have full knowledge of the intent of the scheme, isolation points, simulation scenarios, and restoration to normal procedures.
>
> The concept is to validate the overall performance of the scheme, including the logic where applicable, to validate the overall throughput times against system modeling for different types of Contingencies, and to verify scheme performance as well as the inputs and outputs.

If a RAS passes a functional test, it is not necessary to provide that specific information to the RC because that is the expected result and requires no further action. If a segment of a RAS fails a functional test, the status of that degraded RAS is required to be reported (in Real-time) to the Transmission Operator via PRC-001, Requirement R6, then to the RC via TOP-001-3, Requirement R8. See Phase 2 of Project 2007-06 for the mapping document from PRC-001 to other standards regarding notification of RC by TOP if a deficiency is found during testing. Consequently, it is not necessary to include a similar requirement in this standard.

The initial test interval begins on the effective date of the standard pursuant to the implementation plan. Subsequently, the maximum allowable interval between functional tests is six full calendar years for RAS that are not designated as limited impact RAS and twelve full calendar years for RAS that are designated as limited impact RAS. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. A RAS-entity may choose to count a correct RAS operation as a qualifying functional test for those RAS segments which operate. If a System event causes a correct, but partial RAS operation, separate functional tests of the segments that did not operate are still required within the maximum test interval that started on the date of the previous successful test of those (non-operating) segments in order to be compliant with Requirement R8.

Requirement R9

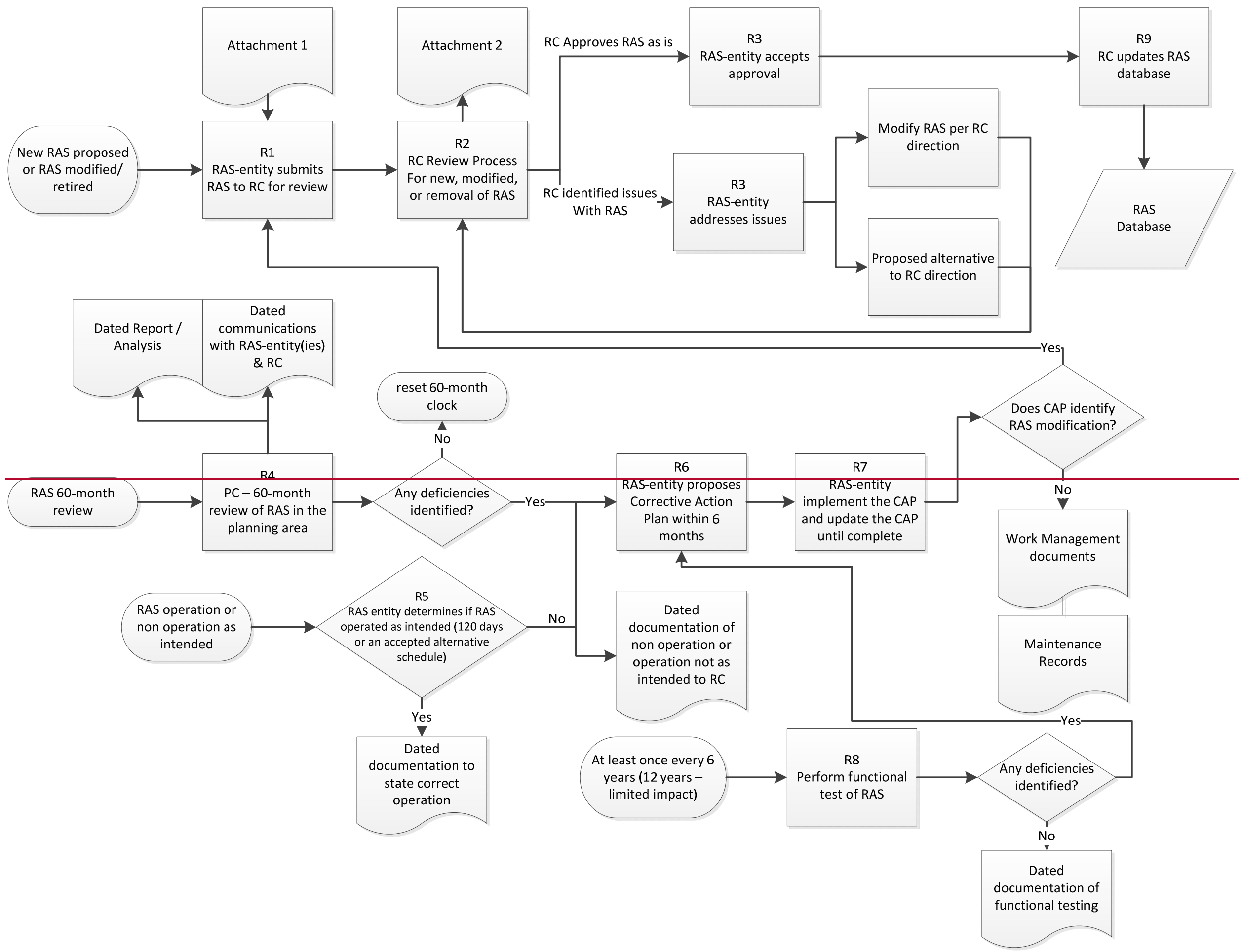
The RAS database required to be maintained by the RC in Requirement R9 ensures information regarding existing RAS is available~~ to entities with a potential reliability need.~~. Attachment 3 contains the minimum information that is required to be included about each RAS listed in the database. Additional information can be requested by the RC.

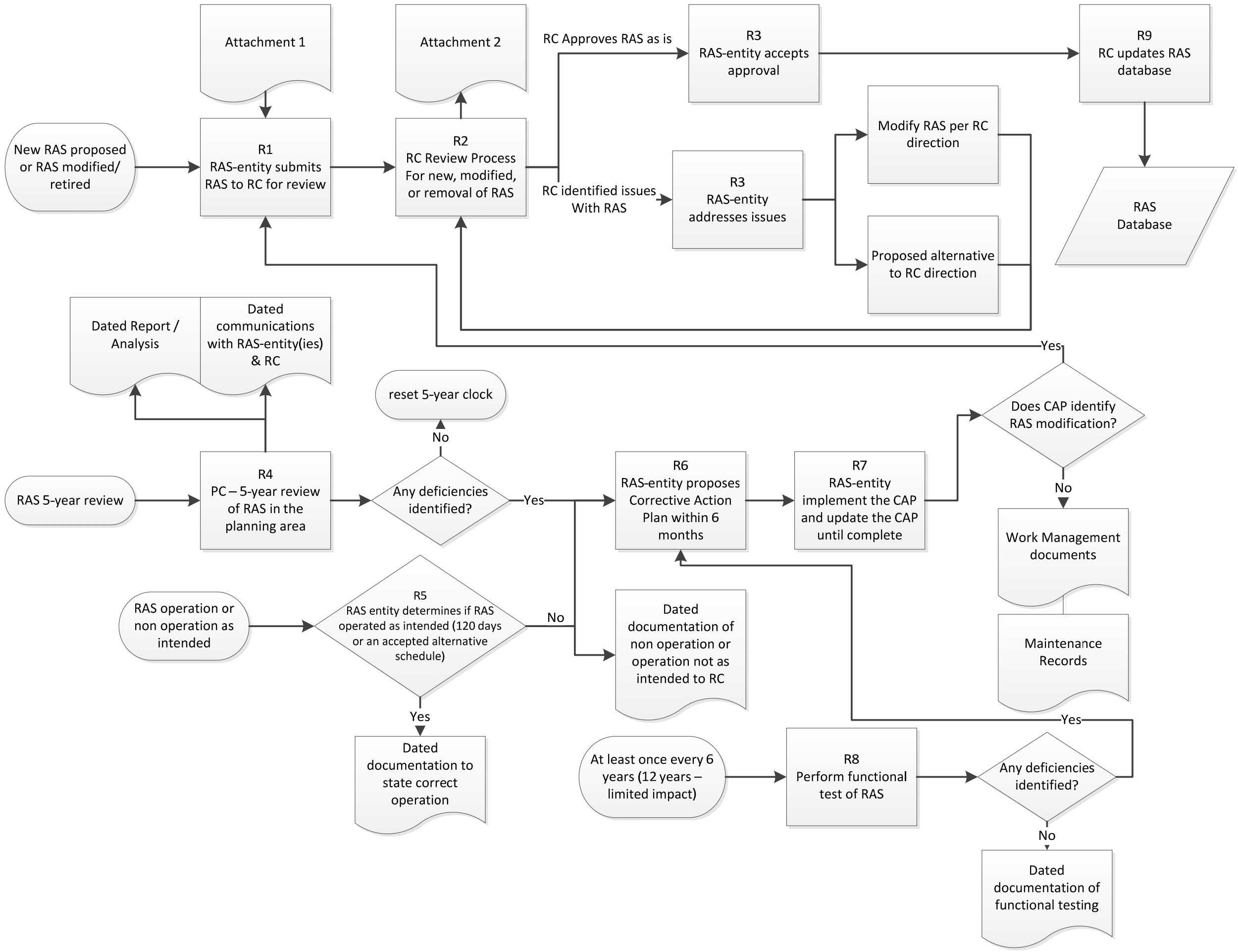
The database enables the RC to provide other entities high-level information on existing RAS that could potentially impact the operational and/or planning activities of that entity. The information provided is sufficient for an entity with a reliability need to evaluate whether the RAS can impact its System. For example, a RAS performing generation rejection to mitigate an overload on a transmission line may cause a power flow change within an adjacent entity area. This entity should be able to evaluate the risk that a RAS poses to its System from the high-level information provided in the RAS database.

The RAS database does not need to list detailed settings or modeling information, but the description of the System performance issues, System conditions, and the intended corrective actions must be included. If additional details about the RAS operation are required, the entity may obtain the contact information of the RAS-entity from the RC.

Process Flow Diagram

The diagram below depicts the process flow of the PRC-012-2 requirements.


Attachment 1
Attachment 2
RC Approves RAS as is
R3
RAS-entity accepts approval
R9
RC updates RAS database
New RAS proposed or RAS modified/ retired
R1
RAS-entity submits RAS to RC for review
R2
RC Review Process For new, modified, or removal of RAS
RC identified issues With RAS
R3
RAS-entity addresses issues
Modify RAS per RC direction
Proposed alternative to RC direction
RAS Database
Dated Report / Analysis
Dated communications with RAS-entity(ies) & RC
reset 60-month clock
No
Yes
Does CAP identify RAS modification?
RAS 60-month review
R4
PC – 60-month review of RAS in the planning area
Any deficiencies identified?
Yes
R6
RAS-entity proposes Corrective Action Plan within 6 months
R7
RAS-entity implement the CAP and update the CAP until complete
No
Work Management documents
Maintenance Records
RAS operation or non operation as intended
R5
RAS entity determines if RAS operated as intended (120 days or an accepted alternative schedule)
No
Dated documentation of non operation or operation not as intended to RC
Yes
Dated documentation to state correct operation
Yes
At least once every 6 years (12 years – limited impact)
R8
Perform functional test of RAS
Any deficiencies identified?
No
Dated documentation of functional testing


Attachment 1
Attachment 2
RC Approves RAS as is
R3
RAS-entity accepts approval
R9
RC updates RAS database
New RAS proposed or RAS modified/ retired
R1
RAS-entity submits RAS to RC for review
R2
RC Review Process For new, modified, or removal of RAS
Modify RAS per RC direction
RC identified issues With RAS
R3
RAS-entity addresses issues
RAS Database
Proposed alternative to RC direction
Dated Report / Analysis
Dated communications with RAS-entity(ies) & RC
Yes
reset 5-year clock
No
Does CAP identify RAS modification?
R4
PC – 5-year review of RAS in the planning area
R6
RAS-entity proposes Corrective Action Plan within 6 months
R7
RAS-entity implement the CAP and update the CAP until complete
RAS 5-year review
Any deficiencies identified?
Yes
No
Work Management documents
R5
RAS entity determines if RAS operated as intended (120 days or an accepted alternative schedule)
RAS operation or non operation as intended
No
Dated documentation of non operation or operation not as intended to RC
Maintenance Records
Yes
Yes
Dated documentation to state correct operation
At least once every 6 years (12 years – limited impact)
R8
Perform functional test of RAS
Any deficiencies identified?
No
Dated documentation of functional testing

Technical Justifications for Attachment 1 Content
Supporting Documentation for RAS Review

To perform an adequate review of the expected reliability implications of a Remedial Action Scheme (RAS), it is necessary for the RAS-entity(ies) to provide a detailed list of information describing the RAS to the reviewing RC. If there are multiple RAS-entities for a single RAS, information will be needed from all RAS-entities. Ideally, in such cases, a single RAS-entity will take the lead to compile all the data identified into a single Attachment 1.

The necessary data ranges from a general overview of the RAS to summarized results of transmission planning studies, to information about hardware used to implement the RAS. Coordination between the RAS and other RAS and protection and control systems will be examined for possible adverse interactions. This review can include wide-ranging electrical design issues involving the specific hardware, logic, telecommunications, and other relevant equipment and controls that make up the RAS.

Attachment 1

The following checklist identifies important RAS information for each new or functionally modified[8] RAS that the RAS-entity shall document and provide to the RC for review pursuant to Requirement R1. When a RAS has been previously reviewed, only the proposed modifications to that RAS require review; however, it will be helpful to each reviewing RC if the RAS-entity provides a summary of the existing RAS functionality.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.

   Provide a description of the RAS to give an overall understanding of the functionality and a map showing the location of the RAS. Identify other protection and control systems requiring coordination with the RAS. See RAS Design below for additional information.

   Provide a single-line drawing(s) showing all sites involved. The drawing(s) should provide sufficient information to allow the RC review team to assess design reliability, and should include information such as the bus arrangement, circuit breakers, the associated switches, etc. For each site, indicate whether detection, logic, action, or a combination of these is present.

2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.

3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP. [Reference NERC Reliability Standard PRC-012-2, Requirements R5 and R7]

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[8] Functionally Modified: Any modification to a RAS consisting of any of the following:

- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond ~~error~~ correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

Provide a description of any functional modifications to a RAS that are part of a CAP that are proposed to address performance deficiency(ies) identified in the periodic evaluation pursuant to Requirement R4, the analysis of an actual RAS operation pursuant to Requirement R5, or functional test failure pursuant to Requirement R8. A copy of the most recent CAP must be submitted in addition to the other data specified in Attachment 1.

4. Initial data to populate the RAS database.
    a. RAS name.
    b. Each RAS-entity and contact information.
    c. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent ~~60~~five full calendar ~~month~~year (Requirement R4) evaluation date; and, date of retirement, if applicable.
    d. System performance issue or reason for installing the RAS (*e.g.*, thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery).
    e. Description of the Contingencies or System conditions for which the RAS was designed (initiating conditions).
    f. Corrective action taken by the RAS.
    g. Identification of limited impact[9] RAS.
    h. Any additional explanation relevant to high level understanding of the RAS.

    Note: This is the same information as is identified in Attachment 3. Supplying the data at this point in the review process ensures a more complete review and minimizes any administrative burden on the reviewing RC(s).

II. Functional Description and Transmission Planning Information

1. Contingencies and System conditions that the RAS is intended to remedy. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.1]
    a. The System conditions that would result if no RAS action occurred should be identified.
    b. Include a description of the System conditions that should arm the RAS so as to be ready to take action upon subsequent occurrence of the critical System Contingencies or other operating conditions when RAS action is intended to occur. If no arming conditions are required, this should also be stated.

[9] A RAS designated as ~~"~~limited impact~~"~~ cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. ~~See Attachment 2 for a description of the limited impact determination by the Reliability Coordinator. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.~~

   c. Event-based RAS are triggered by specific Contingencies that initiate mitigating action. Condition-based RAS may also be initiated by specific Contingencies, but specific Contingencies are not always required. These triggering Contingencies and/or conditions should be identified.

2. The actions to be taken by the RAS in response to disturbance conditions. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.2]

   Mitigating actions are designed to result in acceptable System performance. These actions should be identified, including any time constraints and/or "backup" mitigating measures that may be required in case of a single RAS component failure.

3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and ~~when~~the date those technical studies were performed. [Reference NEC Reliability Standard PRC-014, R3.2]

   Review the scheme purpose and impact to ensure it is (still) necessary, serves the intended purposes, and meets current performance requirements. While copies of the full, detailed studies may not be necessary, any abbreviated descriptions of the studies must be detailed enough to allow the reviewing RC(s) to be convinced of the need for the scheme and the results of RAS-related operations.

4. Information regarding any future System plans that will impact the RAS. [Reference NERC Reliability Standard PRC-014, R3.2]

   The RC's other responsibilities under the NERC Reliability Standards focus on the Operating Horizon, rather than the Planning Horizon. As such, the RC is less likely to be aware of any longer range plans that may have an impact on the proposed RAS. ~~-~~Such knowledge of future Plans is helpful to provide perspective on the capabilities of the RAS.

5. RAS-entity ~~proposed designation as "~~proposal and justification for limited impact~~" or not~~ designation, if applicable.

   A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of ~~this standard~~ PRC-012-2 that has been through the regional review ~~process and designated as~~processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type 3 in NPCC~~, Type 2 in ERCOT, or LAPS in WECC will be~~ is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of ~~Requirement 4, Parts 4.1.3 and 4.1.4~~this standard and is subject to all applicable requirements.

6. Documentation ~~showing that~~ describing the System performance resulting from the possible inadvertent operation of the RAS~~ resulting from~~, except for limited impact RAS, caused by any single RAS component malfunction~~ satisfies~~. Single component

malfunctions in a RAS not determined to be limited impact must satisfy all of the following:
[Reference NERC Reliability Standard PRC-012, R1.4]

a. The BES shall remain stable.

b. Cascading shall not occur.

c. Applicable Facility Ratings shall not be exceeded.

d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

7. An evaluation indicating that the RAS settings and operation avoids adverse interactions with other RAS, and protection and control systems.
[Reference NERC Reliability Standards PRC-012, R1.5 and PRC-014, R3.4]

   RAS are complex schemes that may take action such as tripping load or generation or re-configuring the System. Many RAS depend on sensing specific System configurations to determine whether they need to arm or take actions. An examples of an adverse interaction: A RAS that reconfigures the System also changes the available fault duty, which can affect distance relay overcurrent ("fault detector") supervision and ground overcurrent protection coordination.

8. Identification of other affected RCs.

   This information is needed to aid in information exchange among all affected entities and coordination of the RAS with other RAS and protection and control systems.

III. Implementation

1. Documentation describing the applicable equipment used for detection, dc supply, communications, transfer trip, logic processing, control actions, and monitoring.

   Detection
   Detection and initiating devices, whether for arming or triggering action, should be designed to be secure. Several types of devices have been commonly used as disturbance, condition, or status detectors:

   - Line open status (event detectors),
   - Protective relay inputs and outputs (event and parameter detectors),
   - Transducer and IED (analog) inputs (parameter and response detectors),
   - Rate of change (parameter and response detectors).

   DC Supply
   Batteries and charges, or other forms of dc supply for RAS, are commonly also used for Protection Systems. This is acceptable, and maintenance of such supplies is covered by

PRC-005. However, redundant RAS systems, when used, should be supplied from separately protected (fused or breakered) circuits.

Communications: Telecommunications Channels~~ and Transfer Trip Equipment~~

Telecommunications channels used for sending and receiving RAS information between sites and/or transfer trip devices should meet at least the same criteria as other relaying protection communication channels. Discuss performance of any non-deterministic communication systems used (such as Ethernet).

The scheme logic should be designed so that loss of the channel, noise, or other channel or equipment failure will not result in a false operation of the scheme.

It is highly desirable that the channel equipment and communications media (power line carrier, microwave, optical fiber, etc.) be owned and maintained by the RAS-entity, or perhaps leased from another entity familiar with the necessary reliability requirements. All channel equipment should be monitored and alarmed to the dispatch center so that timely diagnostic and repair action shall take place upon failure. Publicly switched telephone networks are generally an undesirable option.

Communication channels should be well labeled or identified so that the personnel working on the channel can readily identify the proper circuit. Channels between entities should be identified with a common name at all terminals.

Transfer Trip

Transfer trip equipment, when separate from other RAS equipment, should be monitored and labeled similarly to the channel equipment.

Logic Processing

All RAS require some form of logic processing to determine the action to take when the scheme is triggered. Required actions are always scheme dependent. Different actions may be required at different arming levels or for different Contingencies. Scheme logic may be achievable by something as simple as wiring a few auxiliary relay contacts or by much more complex logic processing.

Platforms that have been used reliably and successfully include PLCs in various forms, personal computers (PCs), microprocessor protective relays, remote terminal units (RTUs), and logic processors. Single-function relays have been used historically to implement RAS, but this approach is now less common except for very simple new RAS or minor additions to existing RAS.

Control Actions

RAS action devices may include a variety of equipment such as transfer trip, protective relays, and other control devices. These devices receive commands from the logic processing function (perhaps through telecommunication facilities) and initiate RAS actions at the sites where action is required.

Monitoring by SCADA/EMS should include at least

- Whether the scheme is in-service or out of service.
    - For RAS that are armed manually, the arming status may be the same as whether the RAS is in-service or out of service.

    - For RAS that are armed automatically, these two states are independent because a RAS that has been placed in-service may be armed or unarmed based on whether the automatic arming criteria have been met.
  - The current operational state of the scheme (available or not).
  - In cases where the RAS requires single component failure performance; e.g., redundancy, the minimal status indications should be provided separately for each system.
    - The minimum status is generally sufficient for operational purposes; however, where possible it is often useful to provide additional information regarding partial failures or the status of critical components to allow the RAS-entity to more efficiently troubleshoot a reported failure. Whether this capability exists will depend in part on the design and vintage of equipment used in the RAS. While all schemes should provide the minimum level of monitoring, new schemes should be designed with the objective of providing monitoring at least similar to what is provided for microprocessor-based Protection Systems.

2. Information on detection logic and settings/parameters that control the operation of the RAS. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.3]

   Several methods to determine line or other equipment status are in common use, often in combination:

   a. Auxiliary switch contacts from circuit breakers and disconnect switches (52a/b, 89a/b)—the most common status monitor; "a" contacts exactly emulate actual breaker status, while "b" contacts are opposite to the status of the breaker;

   b. Undercurrent detection—a low level indicates an open condition, including at the far end of a line; pickup is typically slightly above the total line-charging current;

   c. Breaker trip coil current monitoring—typically used when high-speed RAS response is required, but usually in combination with auxiliary switch contacts and/or other detection because the trip coil current ceases when the breaker opens; and

   d. Other detectors such as angle, voltage, power, frequency, rate of change of the aforementioned, out of step, etc. are dependent on specific scheme requirements, but some forms may substitute for or enhance other monitoring described in items 'a', 'b', and 'c' above.

   Both RAS arming and action triggers often require monitoring of analog quantities such as power, current, and voltage at one or more locations and are set to detect a specific level of the pertinent quantity. These monitors may be relays, meters, transducers, or other devices

3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in-service or is being maintained.

In this context, a multifunction device (e.g., microprocessor-based relay) is a single component that is used to perform the function of a RAS in addition to protective relaying and/or SCADA simultaneously. It is important that other applications in the multifunction device do not compromise the functionality of the RAS when the device is in service or when it is being maintained. The following list outlines considerations when the RAS function is applied in the same microprocessor-based relay as equipment protection functions:

a. Describe how the multifunction device is applied in the RAS.

b. Show the general arrangement and describe how the multi-function device is labeled in the design and application, so as to identify the RAS and other device functions.

c. Describe the procedures used to isolate the RAS function from other functions in the device.

d. Describe the procedures used when each multifunction device is removed from service and whether coordination with other protection schemes is required.

e. Describe how each multifunction device is tested, both for commissioning and during periodic maintenance testing, with regard to each function of the device.

f. Describe how overall periodic RAS functional and throughput tests are performed if multifunction devices are used for both local protection and RAS.

g. Describe how upgrades to the multifunction device, such as firmware upgrades, are accomplished. How is the RAS function taken into consideration?

Other devices that are usually not considered multifunction devices such as auxiliary relays, control switches, and instrument transformers may serve multiple purposes such as protection and RAS. Similar concerns apply for these applications as noted above.

4. Documentation describing the System performance resulting from a single component failure in the RAS, except for limited impact RAS, when the RAS is intended to operate. A single component failure in a RAS not determined to be limited impact must 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 is designed. The documentation should describe or illustrate how the design achieves this objective. [Reference NERC Reliability Standard PRC-012, R1.3]

   RAS automatic arming, if applicable, is vital to RAS and System performance and is therefore included in this requirement. Acceptable methods to achieve this objective include, but are not limited to the following:

   a. Providing redundancy of RAS components. Typical examples are listed below:

      i. Protective or auxiliary relays used by the RAS.

      ii. Communications systems necessary for correct operation of the RAS.

iii. Sensing devices used to measure electrical or other quantities used by the RAS.

iv. Station dc supply associated with RAS functions.

v. Control circuitry associated with RAS functions through the trip coil(s) of the circuit breakers or other interrupting devices.

vi. Logic processing devices that accept System inputs from RAS components or other sources, make decisions based on those inputs, or initiate output signals to take remedial actions.

b. Arming more load or generation than necessary such that failure of the RAS to drop a portion of load or generation due to that single component failure will still result in satisfactory System performance, as long as tripping the total armed amount of load or generation does not cause other adverse impacts to reliability.

c. Using alternative automatic actions to back up failures of single RAS components.

d. 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.

5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies important RAS information for each existing RAS to be retired that the RAS-entity shall document and provide to the Reliability Coordinator for review pursuant to Requirement R1.

1. Information necessary to ensure that the Reliability Coordinator is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of technical studies and technical justifications, if applicable, upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

While the documentation necessary to evaluate RAS removals is not as extensive as for new or functionally modified RAS, it is still vital that, when the RAS is no longer available, System performance will still meet the appropriate (usually TPL) requirements for the Contingencies or System conditions that the RAS had been installed to remediate.

Technical Justification for Attachment 2 Content

Reliability Coordinator RAS Review Checklist

Attachment 2 is a checklist provided to facilitate consistent reviews continent-wide for new or functionally modified RAS prior to the RAS installation. The checklist is meant to assist the RC in identifying reliability-related considerations relevant to various aspects of RAS design and implementation.

Technical Justifications for Attachment 3 Content

Database Information

Attachment 3 contains the minimum information that the RC must consolidate into its database for each RAS in its area.

1. RAS name.
   - The name used to identify the RAS.
2. Each RAS-entity and contact information.
   - A reliable phone number or email address should be included to contact each RAS-entity if more information is needed.
3. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent ~~60~~five full calendar ~~month~~year (Requirement R4) evaluation date; and, date of retirement, if applicable.
   - Specify each applicable date.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery).
   - A short description of the reason for installing the RAS is sufficient, as long as the main System issues addressed by the RAS can be identified by someone with a reliability need.
5. Description of the Contingencies or System conditions for which the RAS was designed (initiating conditions).
   - A high level summary of the conditions/Contingencies is expected. Not all combinations of conditions are required to be listed.
6. Corrective action taken by the RAS.
   - A short description of the actions should be given. For schemes shedding load or generation, the maximum amount of megawatts should be included.

7. Identification of limited impact[10] RAS.
    - Specify whether or not the RAS is designated as limited impact.
8. Any additional explanation relevant to high-level understanding of the RAS.
    - If deemed necessary, any additional information can be included in this section, but is not mandatory.

[10] A RAS designated as ~~"~~limited impact~~"~~ cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. ~~A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact.~~

Implementation Plan for PRC-012-2

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

Requested Approval

- PRC-012-2 – Remedial Action Schemes

Requested Retirements

- PRC-012-1 – Remedial Action Scheme Review Procedure
- PRC-013-1 – Remedial Action Scheme Database
- PRC-014-1 – Remedial Action Scheme Assessment
- PRC-015-1 – Remedial Action Scheme Data and Documentation
- PRC-016-1 – Remedial Action Scheme Misoperations

Applicable Entities

- Reliability Coordinator
- Planning Coordinator
- RAS-entity – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS

Background

On November 13, 2014, the NERC Board of Trustees approved revisions to the definition for Remedial Action Scheme ("RAS") and associated revisions to related Reliability Standards to consolidate that term with the Glossary term "Special Protection System" (SPS).

In its February 3, 2015 petition to the Commission for approval of the definition of RAS and associated Reliability Standards ("Petition"), NERC noted that, although PRC-012-0, PRC-013-0, and PRC-014-0 were neither approved nor remanded by the Commission in Order No. 693 and were therefore not enforceable, NERC revised these standards to account for the RAS definition revision and changed relevant version numbers to reflect the change. Because of this change, NERC requested retirement of PRC-012-0, PRC-013-0, and PRC-014-0, and provided, for informational purposes only, updated Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1. In the same Petition, NERC requested retirement of PRC-015-0 and PRC-016-0.1 and approval of Reliability Standards PRC-015-1 and PRC-016-1, again implementing changes stemming from the revised definition of RAS.

On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to accept the revisions to the RAS definition and associated standards, and on November 19, 2015, the Commission issued a Final Order approving the RAS definition and associated standards.

General Considerations

Reliability Standard PRC-012-2 was developed to consolidate previously unapproved standards which were designated by the Commission as “fill-in-the-blank” standards and to revise other RAS-related standards. Reliability Standard PRC-012-2 also provides clear and unambiguous responsibilities to the specific users, owners, and operators of the Bulk-Power System. Reliability Standard PRC-012-2 establishes a new working framework between RAS-entities, PCs, and RCs, and this new framework will involve considerable start-up effort. As such, implementation of Reliability Standard PRC-012-2 will occur over a thirty six (36) month period after approval of the standard by applicable governmental authorities.

Limited Impact RAS

A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type 3 in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 and is subject to all applicable requirements.

Effective Date

Where approval by an applicable governmental authority is required, Reliability Standard PRC-012-2 shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the effective date of the applicable governmental authority’s order approving the standard, or as otherwise provided for by the applicable governmental authority. Provisions concerning the initial performance of obligations under Requirements R4, R8, and R9 are outlined below.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction. Provisions concerning the initial performance of obligations under Requirements R4, R8, and R9 are outlined below.

Requirement R4

For existing RAS, initial performance of obligations under Requirement R4 must be completed within five (5) full calendar years after the effective date of PRC-012-2, as described above.

For new or functionally modified RAS, the initial performance of Requirement R4 must be completed within five (5) full calendar years after the date that the RAS is approved by the reviewing RC(s) under Requirement R3.

Requirement R8

For each RAS not designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within six (6) full calendar years after the effective date for PRC-012-2, as described above.

For each RAS designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within twelve (12) full calendar years after the effective date for PRC-012-2, as described above.

Requirement R9

For each Reliability Coordinator that does not have a RAS database, the initial obligation under Requirement R9 is to establish a database by the effective date of PRC-012-2.

Each Reliability Coordinator will perform the obligation of Requirement R9 within twelve full calendar months after the effective date of PRC-012-2, as described above.

Retirement of Existing Standards

The Reliability Standards for retirement shall be retired immediately prior to the effective date of PRC-012-2 in the particular jurisdiction in which the standard is becoming effective.

Implementation Plan for PRC-012-2

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

Requested Approval

- PRC-012-2 – Remedial Action Schemes

Requested Retirements

- PRC-012-1 – Remedial Action Scheme Review Procedure
- PRC-013-1 – Remedial Action Scheme Database
- PRC-014-1 – Remedial Action Scheme Assessment
- PRC-015-1 – Remedial Action Scheme Data and Documentation
- PRC-016-1 – Remedial Action Scheme Misoperations

Applicable Entities

- Reliability Coordinator
- Planning Coordinator
- RAS-entity – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS

Background

On November 13, 2014, the NERC Board of Trustees approved revisions to the definition for Remedial Action Scheme (“RAS”) and associated revisions to related Reliability Standards to consolidate that term with the Glossary term “Special Protection System” (SPS).

In its February 3, 2015 petition to the Commission for approval of the definition of RAS and associated Reliability Standards (“Petition”), NERC noted that, although PRC-012-0, PRC-013-0, and PRC-014-0 were neither approved nor remanded by the Commission in Order No. 693 and were therefore not enforceable, NERC revised these standards to account for the RAS definition revision and changed relevant version numbers to reflect the change. Because of this change, NERC requested retirement of PRC-012-0, PRC-013-0, and PRC-014-0, and provided, for informational purposes only, updated Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1. In the same Petition, NERC requested retirement of PRC-015-0 and PRC-016-0.1 and approval of Reliability Standards PRC-015-1 and PRC-016-1, again implementing changes stemming from the revised definition of RAS.

On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to accept the revisions to the RAS definition and associated standards, and on November 19, 2015, the Commission issued a Final Order approving the RAS definition and associated standards.

General Considerations

Reliability Standard PRC-012-2 was developed to consolidate previously unapproved standards which were designated by the Commission as “fill-in-the-blank” standards and to revise other RAS-related standards. Reliability Standard PRC-012-2 also provides clear and unambiguous responsibilities to the specific users, owners, and operators of the Bulk-Power System. Reliability Standard PRC-012-2 establishes a new working framework between RAS-entities, PCs, and RCs, and this new framework will involve considerable start-up effort. As such, implementation of Reliability Standard PRC-012-2 will occur over a thirty six (36) month period after approval of the standard by applicable governmental authorities.

Limited Impact RAS

A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type 3 in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 and is subject to all applicable requirements.

Effective Date

Where approval by an applicable governmental authority is required, Reliability Standard PRC-012-2 shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the effective date of the applicable governmental authority’s order approving the standard, or as otherwise provided for by the applicable governmental authority. Provisions concerning the initial performance of obligations under Requirements R4, R8, and R9 are outlined below.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction. Provisions concerning the initial performance of obligations under Requirements R4, R8, and R9 are outlined below.

Requirement R4

For existing RAS, initial performance of obligations under Requirement R4 must be completed within ~~sixty (60~~five (5) full calendar ~~months of~~years after the effective date of PRC-012-2, as described above.

For new or functionally modified RAS, the initial performance of Requirement R4 must be completed within ~~sixty (60~~five (5) full calendar ~~months of~~years after the date that the RAS is approved by the reviewing RC(s) under Requirement R3.

Requirement R8

For each RAS not designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within six (6) full calendar years ~~of~~after the effective date for PRC-012-2, as described above.

For each RAS designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within twelve (12) full calendar years ~~of~~after the effective date for PRC-012-2, as described above.

Requirement R9

For each Reliability Coordinator that does not have a RAS database ~~upon the effective date of PRC-012-2, as described above~~, the initial obligation under Requirement R9 is to establish a database by the effective date of PRC-012-2.

Each Reliability Coordinator will perform the obligation of Requirement R9 within twelve full calendar months after the effective date of PRC-012-2, as described above.

Retirement of Existing Standards

The Reliability Standards for retirement shall be retired immediately prior to the effective date of PRC-012-2 in the particular jurisdiction in which the standard is becoming effective.

Unofficial Comment Form

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

PRC-012-2

DO NOT use this form for submitting comments. Use the electronic form to submit comments on **PRC-012-2 – Remedial Action Schemes**. The electronic comment form must be submitted by **8 p.m. Eastern, Friday, March 18, 2016.**

Documents and information about this project are available on the project page. If you have questions, contact Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

Background Information

This project is addressing all aspects of Remedial Action Schemes (RAS) contained in the RAS-related Reliability Standards: PRC-012-1, PRC-013-1, PRC-014-1, PRC-015-1, and PRC-016-1. The maintenance of the Protection System components associated with RAS (PRC-017-1 Remedial Action Scheme Maintenance and Testing) are already addressed in PRC-005. PRC-012-2 addresses the testing of the non-Protection System components associated with RAS and the overall performance of the RAS.

In FERC Order No. 693 (dated March 16, 2007), the Commission identified PRC-012-0, PRC-013-0, and PRC-014-0 as “fill-in-the-blank” standards and did not approve or remand them. These standards are applicable to the Regional Reliability Organizations (RROs), assigning the RROs the responsibility to establish regional procedures and databases, and to assess and document the operation, coordination, and compliance of RAS. The deference to regional practices precludes the consistent application of RAS-related Reliability Standard requirements.

The proposed draft of PRC-012-2 corrects the applicability of the fill-in-the-blank standards by assigning the requirement responsibilities to the specific users, owners, and operators of the Bulk-Power System; and incorporates the reliability objectives of all the RAS-related standards.

45-day Formal Comment Period

The drafting team appreciates the feedback stakeholders provided on the previous posting. The drafting team considered all of the comments and revised the standard and its implementation plan, making clarifying changes to both documents. Responses to the most prevalent comments received and a summary of the changes to the documents are located in the Consideration of Comments document posted on the project page. Responses to individual comments are not required for a failed additional ballot in accordance with sections 4.12 and 4.13 of the Standards Process Manual. The drafting team will respond to all individual comments received in the last additional ballot; i.e., the passing ballot prior to conducting the Final Ballot. If you have a specific comment that you would like to discuss, please contact the Standards Developer, Al McMeekin at 404-446-9675 or via email Al McMeekin. Please provide your comment, your contact information, and a convenient date and time for a discussion.

The drafting team is soliciting comments and feedback on the revised standard and its implementation plan.

Questions

1. **PRC-012-2:** Requirements R4 and R6, Attachments 1 and 2, and the Supplemental Material section of the standard were modified for clarity and completeness. Do you agree with the proposed changes? If no, please provide the basis for your disagreement and an alternate proposal.

   ☐ Yes
   ☐ No
   Comments:

2. **Implementation Plan for PRC-012-2:** The drafting team revised the Implementation Plan to provide for the initial consideration of limited impact RAS, and to clarify that the initial obligation under Requirement R9 for a Reliability Coordinator that does not have a RAS database is to establish a RAS database by the effective date of PRC-012-2. Do you agree with the revised Implementation Plan? If no, please provide the basis for your disagreement and an alternate proposal.

   ☐ Yes
   ☐ No
   Comments:

Mapping Document

Project 2010-5.3 Phase 3 of Protection Systems: Remedial Action Schemes

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include: **R1.1.** Description of the process for submitting a proposed RAS for Regional Reliability Organization review. **R1.2.** Requirements to provide data that describes design, operation, and modeling of a RAS. **R1.3.** 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.	**PRC-012-1 R.1.1**: Covered by Requirements R1, R2 and R3 **PRC-012-1 R.1.2**: Covered by Requirement R1, Attachment 1 **PRC-012-1 R.1.3**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4, Part 4.1.5 **PRC-012-1 R.1.4**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2, and Requirement R4, Part 4.1.4	**R1.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. **R3.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator. **R4.** Each Planning Coordinator, at least once every five full calendar years, shall:

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1.4. Requirements to demonstrate 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. **R1.5.** Requirements to demonstrate the proposed RAS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures. **R1.6.** Regional Reliability Organization definition of misoperation. **R1.7.** Requirements for analysis and documentation of corrective action plans for all RAS misoperations. **R1.8.** Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure. **R1.9.** Determination, as appropriate, of maintenance and testing requirements.	**PRC-012-1 R.1.5**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4, Part 4.1.2 **PRC-012-1 R.1.6**: Covered by Requirement R5 **PRC-012-1 R.1.7**: Covered by Requirements R5 and R6 **PRC-012-1 R.1.8**: PRC-012-2 NERC Standards Development Process **PRC-012-1 R.1.9**: Covered by Requirement R8	**4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.4.1** The BES shall remain stable. **4.1.4.2** Cascading shall not occur. **4.1.4.3** Applicable Facility Ratings shall not be exceeded. **4.1.4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		established by the Transmission Planner and the Planning Coordinator. **4.1.4.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator. **R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether:

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		5.1.1 The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s). **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R8.** Each RAS-entity shall participate in performing a functional test of each of its RAS to verify the overall RAS

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		performance and the proper operation of non-Protection System components: • At least once every six full calendar years for all RAS not designated as limited impact, or • At least once every twelve full calendar years for all RAS designated as limited impact
R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-013-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a RAS installed shall maintain a RAS database. The database shall include the following types of information:	**PRC-013-1 R1**: Covered by Requirement R9 **PRC-013-1 R1.1, R1.2, R1.3:** Covered by Requirement R9, Attachment 3	**R9.** Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once every twelve full calendar months.

Reliability Standard: PRC-013-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1.1. Design Objectives — Contingencies and system conditions for which the RAS was designed, **R1.2.** Operation — The actions taken by the RAS in response to Disturbance conditions, and **R1.3.** Modeling — Information on detection logic or relay settings that control operation of the RAS.		
R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years	**PRC-014-1 R1**: Covered by Requirement R4	**R4.** Each Planning Coordinator, at least once every five full calendar years, shall:

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
for compliance with NERC Reliability Standards and Regional criteria.		**4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for “limited impact” RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.4.1** The BES shall remain stable. **4.1.4.2** Cascading shall not occur. **4.1.4.3** Applicable Facility Ratings shall not be exceeded. **4.1.4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		established by the Transmission Planner and the Planning Coordinator. **4.1.4.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.
R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all RAS installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).	<u>**PRC-014-1 R2**</u>: Covered by Requirement R4	**R4.** Each Planning Coordinator, at least once every five full calendar years, shall: **4.1** Perform an evaluation of each RAS within its planning area to determine whether:

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.1.1 The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.4.1** The BES shall remain stable. **4.1.4.2** Cascading shall not occur. **4.1.4.3** Applicable Facility Ratings shall not be exceeded. **4.1.4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.1.4.5 Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.
R3. The documentation of the Regional Reliability Organization's RAS assessment shall include the following elements: **R3.1.** Identification of group conducting the assessment and the date the assessment was performed. **R3.2.** Study years, system conditions, and contingencies analyzed in the technical studies on which the	**PRC-014-1 R3**: Covered by Requirement R4 **PRC-014-1 R3.1 - R3.4**: Covered by Requirement R4 **PRC-014-1 R3.5**: Covered by Requirement R6	**R4.** Each Planning Coordinator, at least once every five full calendar years, shall: **4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
assessment is based and when those technical studies were performed. **R3.3.** Identification of RAS that were found not to comply with NERC standards and Regional Reliability Organization criteria. **R3.4.** Discussion of any coordination problems found between a RAS and other protection and control systems. **R3.5.** Provide corrective action plans for non-compliant RAS.		**4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.4.1** The BES shall remain stable. **4.1.4.2** Cascading shall not occur. **4.1.4.3** Applicable Facility Ratings shall not be exceeded. **4.1.4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. **4.1.4.5** Transient voltage responses shall be within acceptable limits as established by the

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		Transmission Planner and the Planning Coordinator. **4.1.5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator. **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8.

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall maintain a list of and provide data for existing and proposed RAS as specified in Reliability Standard PRC-013-1 R1.	**PRC-015-1 R1**: Covered by Requirement R1, Attachment 1	**R1.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located.
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-1_R1 prior to being placed in service.	**PRC-015-1 R2**: Covered by Requirements R1, Attachment 1; R2, Attachment 2; and R3	**R1.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. **R3.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide	Retired P81	N/A

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
documentation of RAS data and the results of Studies that show compliance of new or functionally modified RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).		

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall analyze its RAS operations and maintain a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-1_R1.	**PRC-016-1 R1**: Covered by Requirement R5	**R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall take corrective actions to avoid future misoperations.	**PRC-016-1 R2**: Covered by Requirements R6 and R7	**R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of:

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		• Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R7.** Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: **7.1** Implement the CAP. **7.2** Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).	<u>**PRC-016-1 R3**</u>: Covered by Requirements R5, R6, and R7, Attachment 1	**R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS.

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		5.1.2 The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s). **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R7.** Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: **7.1** Implement the CAP.

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		7.2 Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

Mapping Document

Project 2010-5.3 Phase 3 of Protection Systems: Remedial Action Schemes

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include: **R1.1.** Description of the process for submitting a proposed RAS for Regional Reliability Organization review. **R1.2.** Requirements to provide data that describes design, operation, and modeling of a RAS. **R1.3.** 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.	**PRC-012-1 R.1.1**: Covered by Requirements R1, R2 and R3 **PRC-012-1 R.1.2**: Covered by Requirement R1, Attachment 1 **PRC-012-1 R.1.3**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4, Part 4.1.~~4~~5 **PRC-012-1 R.1.4**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2, and Requirement R4, Part 4.1.~~3~~4	**R1.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. **R3.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator. **R4.** Each Planning Coordinator, at least once every ~~60~~five full calendar ~~months~~years, shall:

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1.4. Requirements to demonstrate 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. **R1.5.** Requirements to demonstrate the proposed RAS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures. **R1.6.** Regional Reliability Organization definition of misoperation. **R1.7.** Requirements for analysis and documentation of corrective action plans for all RAS misoperations. **R1.8.** Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure. **R1.9.** Determination, as appropriate, of maintenance and testing requirements.	**PRC-012-1 R.1.5**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4, Part 4.1.2 **PRC-012-1 R.1.6**: Covered by Requirement R5 **PRC-012-1 R.1.7**: Covered by Requirements ~~R4~~ R5 and R6 **PRC-012-1 R.1.8**: PRC-012-2 NERC Standards Development Process **PRC-012-1 R.1.9**: Covered by Requirement R8	**4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.~~3~~4.1** The BES shall remain stable. **4.1.~~3~~4.2** Cascading shall not occur. **4.1.~~3~~4.3** Applicable Facility Ratings shall not be exceeded. **4.1.~~3~~4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		established by the Transmission Planner and the Planning Coordinator. **4.1.~~3~~4.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.~~4~~5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator. **R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether:

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		5.1.1 The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s). **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R8.** Each RAS-entity shall participate in performing a functional test of each of its RAS to verify the overall RAS

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		performance and the proper operation of non-Protection System components: • At least once every six full calendar years for all RAS not designated as limited impact, or • At least once every twelve full calendar years for all RAS designated as limited impact
R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-013-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a RAS installed shall maintain a RAS database. The database shall include the following types of information:	**PRC-013-1 R1**: Covered by Requirement R9 **PRC-013-1 R1.1, R1.2, R1.3:** Covered by Requirement R9, Attachment 3	**R9.** Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once every twelve full calendar months.

Reliability Standard: PRC-013-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1.1. Design Objectives — Contingencies and system conditions for which the RAS was designed, **R1.2.** Operation — The actions taken by the RAS in response to Disturbance conditions, and **R1.3.** Modeling — Information on detection logic or relay settings that control operation of the RAS.		
R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years	**PRC-014-1 R1**: Covered by Requirement R4	**R4.** Each Planning Coordinator, at least once every ~~60~~five full calendar ~~months~~years, shall:

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
for compliance with NERC Reliability Standards and Regional criteria.		**4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.~~3~~4.1** The BES shall remain stable. **4.1.~~3~~4.2** Cascading shall not occur. **4.1.~~3~~4.3** Applicable Facility Ratings shall not be exceeded. **4.1.~~3~~4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		established by the Transmission Planner and the Planning Coordinator. **4.1.~~3~~4.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.~~4~~5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.
R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all RAS installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).	**PRC-014-1 R2**: Covered by Requirement R4	**R4.** Each Planning Coordinator, at least once every ~~60~~five full calendar ~~months~~years, shall: **4.1** Perform an evaluation of each RAS within its planning area to determine whether:

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.1.1 The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.~~3~~4.1** The BES shall remain stable. **4.1.~~3~~4.2** Cascading shall not occur. **4.1.~~3~~4.3** Applicable Facility Ratings shall not be exceeded. **4.1.~~3~~4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.1.~~3~~4.5 Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.~~4~~5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.
R3. The documentation of the Regional Reliability Organization's RAS assessment shall include the following elements: **R3.1.** Identification of group conducting the assessment and the date the assessment was performed. **R3.2.** Study years, system conditions, and contingencies analyzed in the technical studies on which the	**PRC-014-1 R3**: Covered by Requirement R4 **PRC-014-1 R3.1 - R3.4:** Covered by Requirement R4 **PRC-014-1 R3.5**: Covered by Requirement R6	**R4.** Each Planning Coordinator, at least once every ~~60~~five full calendar ~~months~~years, shall: **4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
assessment is based and when those technical studies were performed. **R3.3.** Identification of RAS that were found not to comply with NERC standards and Regional Reliability Organization criteria. **R3.4.** Discussion of any coordination problems found between a RAS and other protection and control systems. **R3.5.** Provide corrective action plans for non-compliant RAS.		**4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for "limited impact" RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.~~3~~4.1** The BES shall remain stable. **4.1.~~3~~4.2** Cascading shall not occur. **4.1.~~3~~4.3** Applicable Facility Ratings shall not be exceeded. **4.1.~~3~~4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. **4.1.~~3~~4.5** Transient voltage responses shall be within acceptable limits as established by the

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		Transmission Planner and the Planning Coordinator. **4.1.~~4~~5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator. **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8.

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall maintain a list of and provide data for existing and proposed RAS as specified in Reliability Standard PRC-013-1 R1.	**PRC-015-1 R1**: Covered by Requirement R1, Attachment 1	**R1.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located.
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-1_R1 prior to being placed in service.	**PRC-015-1 R2**: Covered by Requirements R1, Attachment 1; R2, Attachment 2; and R3	**R1.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. **R3.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator.

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of RAS data and the results of Studies that show compliance of new or functionally modified RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall analyze its RAS operations and maintain a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-1_R1.	**PRC-016-1 R1**: Covered by Requirement R5	**R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall take corrective actions to avoid future misoperations.	**PRC-016-1 R2**: Covered by Requirements R6 and R7	**R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of:

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		• Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R7.** Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: **7.1** Implement the CAP. **7.2** Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).	PRC-016-1 R3: Covered by Requirements R5, R6, and R7, Attachment 1	**R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS.

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		5.1.2 The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s). **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R7.** Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: **7.1** Implement the CAP.

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		7.2 Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

Violation Risk Factor and Violation Severity Level Justification Document

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

This document provides the standard drafting team (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-012-2. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for PRC-012-2, Requirement R1	
VRF for Requirement R1 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of an entity to submit Attachment 1 information to the responsible Reliability Coordinator for review prior to placing a new or modified RAS in service or retiring an existing RAS could introduce risks to the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R1 relates to two of these areas, specifically (i) protection systems and their coordination; and (ii) clearer criteria for operationally critical facilities. Requirement R1 mandates that entities comply with a review process for new or modified RAS or retirement of RAS. Among the elements of such reviews is the coordination between RAS and other RAS and between RAS and protection and control systems. Requirement R1 also mandates that the RAS-entity provide the Reliability Coordinator relevant RAS information regarding the design and implementation for each new or functionally modified RAS.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements, so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-012-1, Requirement 1, Parts R1.1 – R1.5 which specifies attributes of the RRO process to review RAS (R1.1), provision of pertinent RAS data (R1.2), dependability (R1.3) and security (R1.4) of design, and coordination with other RAS and protection systems (R1.5), and has a Medium VRF.
FERC VRF G4 Discussion	A medium VRF is appropriate for this requirement because failure of an entity to submit Attachment 1 information to the responsible Reliability Coordinator for review prior to placing a new or modified RAS in

VRF Justifications for PRC-012-2, Requirement R1	
VRF for Requirement R1 is Medium	
Guideline 4- Consistency with NERC Definitions of VRFs	service or retiring an existing RAS could introduce risks to the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The RAS-entity failed to provide the information identified in Attachment 1 to each Reliability Coordinator prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R1.

VSL Justifications for PRC-012-2, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-012-1, Requirements R1.1 – R1.5 which had four established Levels of Non-Compliance. The requirement is binary with only a Severe VSL so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2b: N/A
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R2	
VRF for Requirement R2 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R2 because failure of a Reliability Coordinator to perform the RAS reviews and identify potential risks presented by the RAS could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R2 relates to one of these areas, specifically, protection systems and their coordination. Requirement R2 mandates that Reliability Coordinators review the RAS to determine if a RAS avoids adverse interactions with other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-014-1, Requirement R1, which is related to the review of RAS.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R2 because failure of a Reliability Coordinator to perform the RAS reviews and identify potential risks presented by the RAS could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R2	
VRF for Requirement R2 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90 full calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in accordance with Requirement R2.

VSL Justifications for PRC-012-2, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-014-0, Requirement R1 which also had four established Levels of Non-Compliance. This requirement has VSLs comparable to the established Levels of Non-Compliance in that requirement, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R3	
VRF for Requirement R3 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of a RAS entity to address the reliability issues identified during the RC review before placing it into service could introduce risks to the BES that could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R3 relates to one of these areas, specifically protection systems and their coordination. Requirement R3 requires the RAS-entity to address each identified reliability issue which includes the coordination between RAS and other RAS and between RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-015-0 Requirement R2 which requires the entity to comply with the RRO procedure as defined in PRC-012-1 Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of a RAS entity to address the reliability issues identified during the RC review before placing it into service could introduce risks to the BES that could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R3	
VRF for Requirement R3 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The RAS-entity failed to resolve identified reliability issue(s) to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R3.

VSL Justifications for PRC-012-2, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-015-0, Requirement R2 which has four established VSLs. This requirement is binary with only a Severe VSL so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2b: N/A
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R4	
VRF for Requirement R4 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R4 because failure to perform the periodic evaluation could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R4 relates to one of these areas, specifically protection systems and their coordination. Requirement R4 mandates that entities perform periodic evaluations of each RAS to ensure that changes in System conditions have not changed the effectiveness of the RAS to mitigate the events or System conditions for which it was designed. Requirement R4 incorporates all actions necessary to determine if a RAS avoids adverse interactions with other RAS and protection and control systems
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-2, Requirement R3 which requires the assessment of the effectiveness of UVLS Programs.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R4 because failure to perform the periodic evaluation could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R4	
VRF for Requirement R4 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator performed the evaluation as specified in Requirement R4, but was late by less than or equal to 30 full calendar days.	The Planning Coordinator performed the evaluation as specified in Requirement R4, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Planning Coordinator performed the evaluation as specified in Requirement R4, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate one of the Parts 4.1.1 through 4.1.5.	The Planning Coordinator performed the evaluation as specified in Requirement R4, but was late by more than 90 full calendar days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate two or more of the Parts 4.1.1 through 4.1.5. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to provide the results to one or more of the

VSLs for PRC-012-2, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
			receiving entities listed in Part 4.2. OR The Planning Coordinator failed to perform the evaluation in accordance with Requirement R4.

VSL Justifications for PRC-012-2, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-014-0, Requirement R1 which has four established Levels of Non-Compliance. This requirement has comparable VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R4	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R4	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R5	
VRF for Requirement R5 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R5 because failure to perform the RAS operational performance analysis could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R5 relates to one of these areas, specifically protection systems and their coordination. Requirement R5 mandates that entities perform RAS operational performance analysis to verify that the RAS operation and the resulting System performance was consistent with the Contingency events or System conditions for which it was designed. Requirement R5 incorporates all actions necessary to identify coordination issues between RAS and other RAS and between RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-2, Requirements R4 which requires evaluation of the UVLS Program performance during a voltage excursion event.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R5 because failure to perform the RAS operational performance analysis could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R5	
VRF for Requirement R5 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity performed the analysis in accordance with Requirement R5, but was late by less than or equal to 10 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address one of the Parts 5.1.1 through 5.1.4.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address two or more of the Parts 5.1.1 through 5.1.4. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to provide the results (Part 5.2) to one or more of the reviewing Reliability Coordinator(s).

VSLs for PRC-012-2, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
			OR The RAS-entity failed to perform the analysis in accordance with Requirement R5

VSL Justifications for PRC-012-2, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0.1, Requirement R1, and PRC-012-1, Requirement R1.7, which have four established Levels of Non-Compliance. This requirement has comparable VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R5	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R5	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R6	
VRF for Requirement R6 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because the failure of an entity to develop a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R6 addresses one of these areas, specifically protection systems and their coordination. CAPs establish mitigation plans and timetable to address deficiencies that could cause adverse interactions between RAS and other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-016-0, Requirements R2 and R3 which require a RAS-owner take corrective actions to avoid future misoperations and provide documentation of the corrective action plans to the RRO.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because the failure of an entity to develop a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

VRF Justifications for PRC-012-2, Requirement R6	
VRF for Requirement R6 is Medium	
	preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30 full calendar days. OR The RAS-entity developed a Corrective Action Plan but failed to submit it to one or more of its reviewing Reliability Coordinator(s) in accordance with Requirement R6. OR

VSLs for PRC-012-2, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
			The RAS-entity failed to develop a Corrective Action Plan in accordance with Requirement R6.

VSL Justifications for PRC-012-2, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0, Requirements R2 and R3, and has VSLs comparable to the established Levels of Non-Compliance in those requirements, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R6	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R6	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R7	
VRF for Requirement R7 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of an entity to implement a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R7 relates to one of these areas, specifically protection systems and their coordination. Implemented CAPs address deficiencies that could cause adverse interactions between RAS and other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-016-0, Requirements R2 and R3 which require a RAS-owner take corrective actions to avoid future misoperations and provide documentation of the corrective action plans to the RRO.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of an entity to implement a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

VRF Justifications for PRC-012-2, Requirement R7	
VRF for Requirement R7 is Medium	
	preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity implemented a CAP in accordance with Requirement R7, Part 7.1, but failed to update the CAP (Part 7.2) if actions or timetables changed, or failed to notify (Part 7.3) each of the reviewing Reliability Coordinator(s) of the updated CAP or completion of the CAP.	N/A	N/A	The RAS-entity failed to implement a CAP in accordance with Requirement R7, Part 7.1.

VSL Justifications for PRC-012-2, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0, Requirement R2 and has VSLs comparable to the established Levels of Non-Compliance in that requirement, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Lower and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R8	
VRF for Requirement R8 is High	
NERC VRF Discussion	A High VRF is appropriate for this Requirement since failure to perform functional testing may allow latent failures to persist in a RAS. These latent failures could result in an unintended operation or a failure to operate, either of which could directly contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures. For these reasons, the requirement meets the NERC criteria for a High VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R8 has interactions in three of these areas, specifically (i) protection systems and their coordination, (ii) communication protocol and facilities, and (iii) appropriate use of transmission loading relief. RAS interactions occur with protection systems, utilize communication protocols and facilities for proper functioning, and are often used for transmission loading relief.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements, so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-005-3, Requirement R3 which requires the maintenance of Protection System Components and has a VRF of High.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A High VRF is appropriate for this Requirement since failure to perform functional testing may allow latent failures to persist in a RAS. These latent failures could result in an unintended operation or a failure to operate, either of which could directly contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures. For these reasons, the requirement meets the NERC criteria for a High VRF.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VRF Justifications for PRC-012-2, Requirement R8	
VRF for Requirement R8 is High	
mingle More than One Obligation	

VSLs for PRC-012-2, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by less than or equal to 30 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 90 full calendar days. OR The RAS-entity failed to perform the functional test for a RAS as specified in Requirement R8.

VSL Justifications for PRC-012-2, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-017-0, Requirements R1 and R2, which had VSLs of Lower, Moderate, High, and Severe. This requirement has VSLs comparable to the established VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R8	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R9	
VRF for Requirement R9 is Lower	
NERC VRF Discussion	A Lower VRF is appropriate for this requirement because the failure of an entity to update the RAS database, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R9 does not address any of the identified areas; therefore, the FERC VRF G1 Discussion is not applicable.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with PRC-010-2 Requirement R6 and PRC-006-1 Requirement R6, which have an approved VRF of Lower.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A Lower VRF is appropriate for this requirement because the failure of an entity to update the RAS database, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90 full calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

VSL Justifications for PRC-012-2, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-013-0, Requirement R1 and has VSLs comparable to the established Levels of Non-Compliance of that requirements, so there is no consequence of lowering the current level of compliance.

VSL Justifications for PRC-012-2, Requirement R9	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations**FERC VSL G3** Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is based upon a single violation, not a cumulative number of violations.The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

Violation Risk Factor and Violation Severity Level Justification Document

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

This document provides the standard drafting team (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-012-2. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for PRC-012-2, Requirement R1	
VRF for Requirement R1 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of an entity to submit Attachment 1 information to the responsible Reliability Coordinator for review prior to placing a new or modified RAS in service or retiring an existing RAS could introduce risks to the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R1 relates to two of these areas, specifically (i) protection systems and their coordination; and (ii) clearer criteria for operationally critical facilities. Requirement R1 mandates that entities comply with a review process for new or modified RAS or retirement of RAS. Among the elements of such reviews is the coordination between RAS and other RAS and between RAS and protection and control systems. Requirement R1 also mandates that the RAS-entity provide the Reliability Coordinator relevant RAS information regarding the design and implementation for each new or functionally modified RAS.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements, so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-012-1, Requirement 1, Parts R1.1 – R1.5 which specifies attributes of the RRO process to review RAS (R1.1), provision of pertinent RAS data (R1.2), dependability (R1.3) and security (R1.4) of design, and coordination with other RAS and protection systems (R1.5), and has a Medium VRF.
FERC VRF G4 Discussion	A medium VRF is appropriate for this requirement because failure of an entity to submit Attachment 1 information to the responsible Reliability Coordinator for review prior to placing a new or modified RAS in

VRF Justifications for PRC-012-2, Requirement R1	
VRF for Requirement R1 is Medium	
Guideline 4- Consistency with NERC Definitions of VRFs	service or retiring an existing RAS could introduce risks to the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The RAS-entity failed to provide the information identified in Attachment 1 to each Reliability Coordinator prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R1.

VSL Justifications for PRC-012-2, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-012-1, Requirements R1.1 – R1.5 which had four established Levels of Non-Compliance. The requirement is binary with only a Severe VSL so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2b: N/A
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R2	
VRF for Requirement R2 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R2 because failure of a Reliability Coordinator to perform the RAS reviews and identify potential risks presented by the RAS could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R2 relates to one of these areas, specifically, protection systems and their coordination. Requirement R2 mandates that Reliability Coordinators review the RAS to determine if a RAS avoids adverse interactions with other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-014-1, Requirement R1, which is related to the review of RAS.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R2 because failure of a Reliability Coordinator to perform the RAS reviews and identify potential risks presented by the RAS could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R2	
VRF for Requirement R2 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90 full calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in accordance with Requirement R2.

VSL Justifications for PRC-012-2, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-014-0, Requirement R1 which also had four established Levels of Non-Compliance. This requirement has VSLs comparable to the established Levels of Non-Compliance in that requirement, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R3	
VRF for Requirement R3 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of a RAS entity to address the reliability issues identified during the RC review before placing it into service could introduce risks to the BES that could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R3 relates to one of these areas, specifically protection systems and their coordination. Requirement R3 requires the RAS-entity to address each identified reliability issue which includes the coordination between RAS and other RAS and between RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-015-0 Requirement R2 which requires the entity to comply with the RRO procedure as defined in PRC-012-1 Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of a RAS entity to address the reliability issues identified during the RC review before placing it into service could introduce risks to the BES that could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R3	
VRF for Requirement R3 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The RAS-entity failed to resolve identified reliability issue(s) to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R3.

VSL Justifications for PRC-012-2, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-015-0, Requirement R2 which has four established VSLs. This requirement is binary with only a Severe VSL so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2b: N/A
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R4	
VRF for Requirement R4 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R4 because failure to perform the periodic evaluation could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R4 relates to one of these areas, specifically protection systems and their coordination. Requirement R4 mandates that entities perform periodic evaluations of each RAS to ensure that changes in System conditions have not changed the effectiveness of the RAS to mitigate the events or System conditions for which it was designed. Requirement R4 incorporates all actions necessary to determine if a RAS avoids adverse interactions with other RAS and protection and control systems
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-2, Requirement R3 which requires the assessment of the effectiveness of UVLS Programs.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R4 because failure to perform the periodic evaluation could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R4	
VRF for Requirement R4 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator performed the evaluation as specified in ~~accordance with~~ Requirement R4, ~~in greater than 60 full calendar months~~ but was late by less than or equal to ~~6~~130 full calendar ~~months~~days.	The Planning Coordinator performed the evaluation as specified in ~~accordance with~~ Requirement R4, ~~in greater~~but was late by more than ~~6~~130 full calendar ~~months~~days but less than or equal to ~~6~~260 full~~-~~ calendar ~~months~~days.	The Planning Coordinator performed the evaluation as specified in ~~accordance with~~ Requirement R4, ~~in greater~~but was late by more than ~~6~~260 full calendar ~~months~~days but less than or equal to ~~6~~390 full calendar ~~months.~~ days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate one of the Parts 4.1.1 through 4.1.~~4~~5.	The Planning Coordinator performed the evaluation as specified in ~~accordance with~~ Requirement R4, but ~~in greater~~was late by more than ~~6~~390 full calendar ~~months~~days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate two or more of the Parts 4.1.1 through 4.1.~~4~~5. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to provide the

VSLs for PRC-012-2, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
			results to one or more of the receiving entities listed in Part 4.2. OR The Planning Coordinator failed to perform the evaluation in accordance with Requirement R4.

VSL Justifications for PRC-012-2, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-014-0, Requirement R1 which has four established Levels of Non-Compliance. This requirement has comparable VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R4	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R4	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R5	
VRF for Requirement R5 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R5 because failure to perform the RAS operational performance analysis could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R5 relates to one of these areas, specifically protection systems and their coordination. Requirement R5 mandates that entities perform RAS operational performance analysis to verify that the RAS operation and the resulting System performance was consistent with the Contingency events or System conditions for which it was designed. Requirement R5 incorporates all actions necessary to identify coordination issues between RAS and other RAS and between RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-2, Requirements R4 which requires evaluation of the UVLS Program performance during a voltage excursion event.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R5 because failure to perform the RAS operational performance analysis could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R5	
VRF for Requirement R5 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity performed the analysis in accordance with Requirement R5, but was late by less than or equal to 10 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address one of the Parts 5.1.1 through 5.1.4.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address two or more of the Parts 5.1.1 through 5.1.4. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to provide the results (Part 5.2) to one or more of the reviewing Reliability Coordinator(s).

VSLs for PRC-012-2, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
			OR The RAS-entity failed to perform the analysis in accordance with Requirement R5

VSL Justifications for PRC-012-2, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0.1, Requirement R1, and PRC-012-1, Requirement R1.7, which have four established Levels of Non-Compliance. This requirement has comparable VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R5	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R5	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R6	
VRF for Requirement R6 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because the failure of an entity to develop a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R6 addresses one of these areas, specifically protection systems and their coordination. CAPs establish mitigation plans and timetable to address deficiencies that could cause adverse interactions between RAS and other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-016-0, Requirements R2 and R3 which require a RAS-owner take corrective actions to avoid future misoperations and provide documentation of the corrective action plans to the RRO.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because the failure of an entity to develop a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

VRF Justifications for PRC-012-2, Requirement R6	
VRF for Requirement R6 is Medium	
	preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30 full calendar days. OR The RAS-entity developed a Corrective Action Plan but failed to submit it to one or more of its reviewing Reliability Coordinator(s) in accordance with Requirement R6. OR

VSLs for PRC-012-2, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
			The RAS-entity failed to develop a Corrective Action Plan in accordance with Requirement R6.

VSL Justifications for PRC-012-2, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0, Requirements R2 and R3, and has VSLs comparable to the established Levels of Non-Compliance in those requirements, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R6	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R6	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R7	
VRF for Requirement R7 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of an entity to implement a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R7 relates to one of these areas, specifically protection systems and their coordination. Implemented CAPs address deficiencies that could cause adverse interactions between RAS and other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-016-0, Requirements R2 and R3 which require a RAS-owner take corrective actions to avoid future misoperations and provide documentation of the corrective action plans to the RRO.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of an entity to implement a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

VRF Justifications for PRC-012-2, Requirement R7	
VRF for Requirement R7 is Medium	
	preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity implemented a CAP in accordance with Requirement R7, Part 7.1, but failed to update the CAP (Part 7.2) if actions or timetables changed, or failed to notify (Part 7.3) each of the reviewing Reliability Coordinator(s) of the updated CAP or completion of the CAP.	N/A	N/A	The RAS-entity failed to implement a CAP in accordance with Requirement R7, Part 7.1.

VSL Justifications for PRC-012-2, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0, Requirement R2 and has VSLs comparable to the established Levels of Non-Compliance in that requirement, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Lower and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R8	
VRF for Requirement R8 is High	
NERC VRF Discussion	A High VRF is appropriate for this Requirement since failure to perform functional testing may allow latent failures to persist in a RAS. These latent failures could result in an unintended operation or a failure to operate, either of which could directly contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures. For these reasons, the requirement meets the NERC criteria for a High VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R8 has interactions in three of these areas, specifically (i) protection systems and their coordination, (ii) communication protocol and facilities, and (iii) appropriate use of transmission loading relief. RAS interactions occur with protection systems, utilize communication protocols and facilities for proper functioning, and are often used for transmission loading relief.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements, so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-005-3, Requirement R3 which requires the maintenance of Protection System Components and has a VRF of High.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A High VRF is appropriate for this Requirement since failure to perform functional testing may allow latent failures to persist in a RAS. These latent failures could result in an unintended operation or a failure to operate, either of which could directly contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures. For these reasons, the requirement meets the NERC criteria for a High VRF.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VRF Justifications for PRC-012-2, Requirement R8	
VRF for Requirement R8 is High	
mingle More than One Obligation	

VSLs for PRC-012-2, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by less than or equal to 30 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 90 full calendar days. OR The RAS-entity failed to perform the functional test for a RAS as specified in Requirement R8.

VSL Justifications for PRC-012-2, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-017-0, Requirements R1 and R2, which had VSLs of Lower, Moderate, High, and Severe. This requirement has VSLs comparable to the established VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R8	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R9	
VRF for Requirement R9 is Lower	
NERC VRF Discussion	A Lower VRF is appropriate for this requirement because the failure of an entity to update the RAS database, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R9 does not address any of the identified areas; therefore, the FERC VRF G1 Discussion is not applicable.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with PRC-010-2 Requirement R6 and PRC-006-1 Requirement R6, which have an approved VRF of Lower.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A Lower VRF is appropriate for this requirement because the failure of an entity to update the RAS database, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90 full calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

VSL Justifications for PRC-012-2, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-013-0, Requirement R1 and has VSLs comparable to the established Levels of Non-Compliance of that requirements, so there is no consequence of lowering the current level of compliance.

VSL Justifications for PRC-012-2, Requirement R9	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations**FERC VSL G3** Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is based upon a single violation, not a cumulative number of violations.The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

NERC
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RELIABILITY CORPORATION

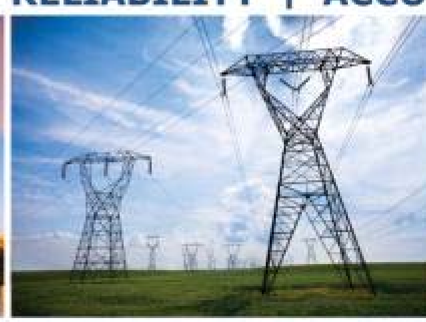
Reliability Standard PRC-012-2 Remedial Action Schemes Question & Answer Document

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

February 2016

RELIABILITY | ACCOUNTABILITY



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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 is the Remedial Action Scheme (RAS) review assigned to the Reliability Coordinator?

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 Reliability Coordinators (RCs) and Planning Coordinators (PCs) 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. The Wide Area purview 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, Planning Coordinator, Transmission Planner, or other entities 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 is not expected to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not contain compliance requirements. If Reliability Standards address functions that are not described in the model, the Reliability Standard requirements take precedence over the Functional Model. For further reference, please see the Introduction section of NERC’s Reliability Functional Model, Version 5, November 2009. 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 five year evaluation of Requirement R4 assigned to the Planning Coordinator?

Requirement R4 states that an evaluation of each RAS must be done at least once every five full calendar years 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, similar to the planning analyses performed by PCs.

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

TOP-1-3 Requirement R13 requires Balancing Authorities (BA) and Transmission Operators (TOP) 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-005-4 requires RCs to share any pertinent data, such as data from RAS, with potentially affected BAs and TOPs. 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.

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

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 the RAS-entities. 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?

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 4.1.5 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.

Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review processes and designated as Type 3 in NPCC or Local Area Protection Scheme (LAPS) in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process. Limited impact schemes are not subject to the single component failure aspect of Requirement R4, Part 4.1.5.

6. What is required for RAS "inadvertent operation" and why?

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-012-1 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 4.1.4 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 4.1.4.1 – 4.1.4.5, which are the performance requirements common to all planning events P0–P7.

Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective

date of this standard that has been through the regional review processes and designated as Type 3 in NPCC or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator in conjunction with the RAS review process. Limited impact schemes are not subject to the single component malfunction aspect of Requirement R4, Part 4.1.4.

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 for continuity with PRC-012-1 R1.3; however, the standard drafting team concluded the classification is unnecessary. The distinction between planning and extreme RAS is captured in Requirement R4, Part 4.1.5 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.

Similarly, the standard drafting team concluded that the SPCS-SAMS distinction between significant and limited RAS was unnecessary for the purpose of maintaining continuity with PRC-012-1, and problematic due to the difficulty of drawing a universally satisfactory delineation in generally worded classification criteria. Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review processes and designated as Type 3 in NPCC or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator in conjunction with the RAS review process.

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 a functional modification of a RAS?

A functional modification to a RAS consists of any of the following:

- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels (addition or removal)

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 device custom logic.
2. Changes to the telecommunication infrastructure or communication facility, such as the replacement of a T1 multiplexor that carries RAS communication when such changes may be important to the 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, or a component that uses the same functionality as the failed component.
2. A firmware upgrade of a RAS component if the change does not require changes in the RAS implementation logic.

The Supplemental Material section of Reliability Standard PRC-012-2 also includes several additional examples of RAS changes that do and do not constitute functional modifications.

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
NERC Staff	Al McMeekin (Standards Developer)	NERC
NERC Staff	Lacey Ourso (Standards Developer)	NERC
NERC Staff	Andrew Wills (Associate Counsel)	NERC

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

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

~~November~~ February 2016~~5~~

RELIABILITY | ACCOUNTABILITY

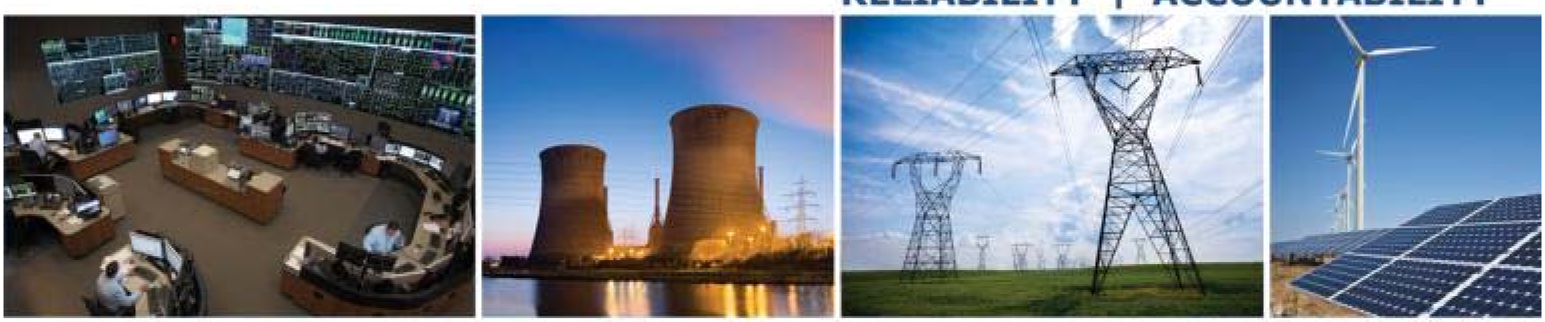

Table of Contents

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 is the Remedial Action Scheme (RAS) review assigned to the Reliability Coordinator?

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 Reliability Coordinators (RCs) and Planning Coordinators (PCs) 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. The Wide Area purview 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, Planning Coordinator, Transmission Planner, or other entities 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 is not expected to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not contain compliance requirements. If Reliability Standards address functions that are not described in the model, the Reliability Standard requirements take precedence over the Functional Model. For further reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009. 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 five year~~60 month~~ evaluation of Requirement R4 assigned to the Planning Coordinator?

Requirement R4 states that an evaluation of each RAS must be done at least once every ~~60~~ five full calendar ~~months~~ years 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, similar to the planning analyses performed by PCs.

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

TOP-1-3 Requirement R13 requires Balancing Authorities (BA) and Transmission Operators~~wners~~ (TOP) 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-005-4 requires RCs to share any pertinent data, such as data from RAS, with potentially affected BAs and TOPs. Operating horizon assessments that include RAS are already required by other standards, so an additional requirement duplicating that effort is not necessary.

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

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 the RAS-entities. 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?

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 4.1.~~4~~ 5 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:
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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
NERC Staff	Al McMeekin (Standards Developer)	NERC
NERC Staff	Lacey Ourso (Standards Developer)	NERC
NERC Staff	Andrew Wills (Associate Counsel)	NERC

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Standards Announcement

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)
PRC-012-2

Formal Comment Period Open through March 18, 2016

Now Available

A 45-day formal comment period for **PRC-012-2 – Remedial Action Schemes** is open through **8 p.m. Eastern, Friday, March 18, 2016**.

The drafting team appreciates the feedback stakeholders provided on the previous posting. The drafting team considered all of the comments and revised the standard and its implementation plan accordingly, making clarifying changes to both documents. Responses to the most prevalent comments received and a summary of the changes to the documents are located in the Consideration of Comments document posted on the project page as responses to individual comments are not required for a failed additional ballot in accordance with sections 4.12 and 4.13 of the Standards Process Manual. The drafting team will respond to all individual comments received in the last additional ballot conducted (the passing ballot) prior to conducting the Final Ballot. If you have a specific comment that you would like to discuss, please contact the Standards Developer, Al McMeekin at 404-446-9675 or via email Al McMeekin. Please provide your comment, your contact information, and a convenient date and time for a discussion.

The drafting team is soliciting comments and feedback on the revised standard and its implementation plan.

Commenting

Use the electronic form to submit comments on the standard. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

An additional ballot and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **March 9-18, 2016**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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Standards Announcement

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)
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North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)
PRC-012-2

Additional Ballot and Non-binding Poll Results

Now Available

A formal comment period and additional ballot for **PRC-012-2 – Remedial Action Schemes**, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded **8 p.m. Eastern, Friday, March 18, 2016.**

The voting statistics are listed below, and the Ballot Results page provides detailed results for the ballot and non-binding poll.

PRC-012-2	Non-binding Poll
Quorum / Approval	Quorum / Supportive Opinions
75.55% / 78.87%	77.52% / 80.00%

Next Steps

The drafting team will consider all responses received during the comment period and determine the next steps of the project.

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North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
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404-446-2560 | www.nerc.com

BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/45)
Ballot Name: 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes PRC-012-2 AB 3 ST
Voting Start Date: 3/9/2016 12:01:00 AM
Voting End Date: 3/18/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 241
Total Ballot Pool: 319
Quorum: 75.55
Weighted Segment Value: 78.87

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	87	1	49	0.778	14	0.222	0	6	18
Segment: 2	9	0.8	7	0.7	1	0.1	0	0	1
Segment: 3	72	1	36	0.766	11	0.234	0	4	21
Segment: 4	23	1	12	0.75	4	0.25	0	0	7
Segment: 5	72	1	38	0.76	12	0.24	0	6	16
Segment: 6	44	1	19	0.731	7	0.269	0	6	12
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	2	0.1	1	0.1	0	0	0	0	1
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

Segment: 10	8	0.6	5	0.5	1	0.1	0	0	2
Totals:	319	6.7	169	5.285	50	1.415	0	22	78

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		None	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Negative	Third-Party Comments
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas		Affirmative	N/A

1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Negative	Comments Submitted
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		None	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	None	N/A
1	Colorado Springs Utilities	Shawna Speer		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		None	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		None	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass	Greg Davis	Negative	Comments Submitted

1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		None	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Alan MacNaughton		None	N/A

1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Charles Raney		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Rod Kinard	Gul Khan	Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Jared Shakespeare		Negative	Comments Submitted
1	PHI - Potomac Electric Power Co.	David Thorne		Affirmative	N/A
1	Platte River Power Authority	John Collins		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	Comments Submitted
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PPL Electric Utilities	Brenda Truhe		Affirmative	N/A

	Corporation				
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith	Pragna Pulusani	Negative	Third-Party Comments
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		None	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Sunflower Electric Power Corporation	Bertha Ellen Watkins		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted

1	Transmission Agency of Northern California	Eric Olson		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Kim Moulton		None	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Michael DeLoach		None	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public	Jeri Freimuth		Negative	Comments

	Service Co.				Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Valerie Reis		Negative	Third-Party Comments
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A
3	Beaches Energy Services	Steven Lancaster		None	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Green Cove Springs	Mark Schultz		None	N/A
3	City of Leesburg	Chris Adkins		None	N/A
3	City of Redding	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A

3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		None	N/A
3	Florida Power & Light	Summer Esquerre		None	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	Third-Party Comments
3	Grand River Dam Authority	Jeff Wells		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Negative	Comments Submitted
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		None	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A

3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Chris Gowder	None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Blaine Dinwiddie		None	N/A
3	Pacific Gas and Electric Company	John Hagen		None	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Negative	Comments Submitted
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None	N/A
3	Puget Sound Energy, Inc.	Andrea Basinski		None	N/A
3	Sacramento	Rachel Moore	Joe Tarantino	Affirmative	N/A

	Municipal Utility District				
3	Salt River Project	John Coggins		None	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		None	N/A
3	Seattle City Light	Dana Wheelock		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith	Larry Heckert	Affirmative	N/A
4	Austin Energy	Tina Garvey		Negative	Third-Party Comments
4	Blue Ridge Power Agency	Duane Dahlquist		None	N/A

4	City of Clewiston	Lynne Mila		None	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		None	N/A
4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Negative	Third-Party Comments
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A
4	Keys Energy Services	Stanley Rzad		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		None	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi	Steve McElhaney		None	N/A

	Electric Power Association				
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Comments Submitted
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
5	Austin Energy	Jeanie Doty		Negative	Third-Party Comments
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Clement Ma		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Third-Party Comments
5	Bonneville Power Administration	Francis Halpin		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Calpine Corporation	Hamid Zakery		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City and County of San Francisco	Daniel Mason		Negative	Comments Submitted
5	City of Independence, Power and Light	Jim Nail		Affirmative	N/A

	Department				
5	City of Redding	Paul Cummings	Bill Hughes	Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle	Kelly Silver	Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Dynegy Inc.	Dan Roethemeyer		Abstain	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		None	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		None	N/A
5	Exelon	Vince Catania		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	David Schumann		None	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		None	N/A
5	Kissimmee Utility Authority	Mike Blough		Affirmative	N/A

5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Lower Colorado River Authority	Wesley Maurer		None	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Third-Party Comments
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		None	N/A
5	Oglethorpe Power Corporation	Teresa Czyz		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	OTP - Otter Tail	Cathy Fogale		Affirmative	N/A

	Power Company				
5	Pacific Gas and Electric Company	Alex Chua		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Abstain	N/A
5	PPL Electric Utilities Corporation	Dan Wilson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Abstain	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	SCANA - South Carolina Electric and Gas Co.	Henry Delk		None	N/A
5	Seattle City Light	Mike Haynes		Negative	Comments Submitted
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tennessee Valley Authority	Brandy Spraker	Dennis Chastain	None	N/A

5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Affirmative	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		None	N/A
5	WEC Energy Group, Inc.	Linda Horn		Negative	Comments Submitted
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Edward P Cox		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Bonneville Power Administration	Alex Spain		Negative	Comments Submitted
6	City of Redding	Marvin Briggs	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	None	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston	Kelly Silver	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Louis Slade		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Earle Saunders		Affirmative	N/A

6	Exelon	Dave Carlson		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	None	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		None	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	Platte River Power Authority	Carol Ballantine		Abstain	N/A
6	Portland General Electric Co.	Adam Menendez		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Negative	Third-Party Comments

6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Hathaway		Negative	Comments Submitted
6	Xcel Energy, Inc.	Peter Colussy	Amy Casuscelli	Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
8	David Kiguel	David Kiguel		None	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A

10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		None	N/A

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/45)
Ballot Name: 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes PRC-012-2 Non-binding Poll AB 3 NB
Voting Start Date: 3/9/2016 12:01:00 AM
Voting End Date: 3/18/2016 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 231
Total Ballot Pool: 297
Quorum: 77.78
Weighted Segment Value: 80

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	79	1	37	0.804	9	0.196	0	19	14
Segment: 2	9	0.6	5	0.5	1	0.1	0	3	0
Segment: 3	69	1	30	0.833	6	0.167	0	11	22
Segment: 4	22	1	8	0.667	4	0.333	0	4	6
Segment: 5	66	1	29	0.784	8	0.216	0	17	12
Segment: 6	40	1	14	0.778	4	0.222	0	12	10
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

Segment: 10	8	0.6	5	0.5	1	0.1	0	0	2
Totals:	297	6.6	132	5.266	33	1.334	0	66	66

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		None	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A

1	Bonneville Power Administration	Donald Watkins		Negative	Comments Submitted
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	None	N/A
1	Colorado Springs Utilities	Shawna Speer		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		None	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass	Greg Davis	Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Affirmative	N/A

1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		None	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service	Charles Raney		Abstain	N/A

	Co.				
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Abstain	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Rod Kinard	Gul Khan	Negative	Comments Submitted
1	Peak Reliability	Jared Shakespeare		Negative	Comments Submitted
1	Platte River Power Authority	John Collins		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith	Pragna Pulusani	Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A

1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		None	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Transmission Agency of Northern California	Eric Olson		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Kim Moulton		None	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	BC Hydro and Power	Venkataramakrishnan		Abstain	N/A

	Authority	Vinnakota			
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Michael DeLoach		None	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Valerie Reis		Negative	Comments Submitted
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Abstain	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A
3	Beaches Energy Services	Steven Lancaster		None	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Central Electric Power	Adam Weber		Affirmative	N/A

	Cooperative (Missouri)				
3	City of Green Cove Springs	Mark Schultz		None	N/A
3	City of Leesburg	Chris Adkins		None	N/A
3	City of Redding	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		None	N/A
3	Florida Power & Light	Summer Esquerre		None	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Grand River Dam	Jeff Wells		None	N/A

	Authority				
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Affirmative	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Chris Gowder	None	N/A
3	OGE Energy - Oklahoma Gas and	Donald Hargrove		Affirmative	N/A

	Electric Co.				
3	Omaha Public Power District	Blaine Dinwiddie		None	N/A
3	Pacific Gas and Electric Company	John Hagen		None	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None	N/A
3	Puget Sound Energy, Inc.	Andrea Basinski		None	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Salt River Project	John Coggins		None	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		None	N/A
3	Seattle City Light	Dana Wheelock		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A

3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith	Larry Heckert	Affirmative	N/A
4	Austin Energy	Tina Garvey		Negative	Comments Submitted
4	Blue Ridge Power Agency	Duane Dahlquist		Affirmative	N/A
4	City of Clewiston	Lynne Mila		None	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		None	N/A
4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		None	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted
4	Illinois Municipal Electric Agency	Bob Thomas		Abstain	N/A
4	Keys Energy Services	Stanley Rzad		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Abstain	N/A
4	Public Utility District No. 1 of Snohomish	John Martinsen		Affirmative	N/A

	County				
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		None	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Michael Ward		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Comments Submitted
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
5	Austin Energy	Jeanie Doty		Abstain	N/A
5	Avista - Avista Corporation	Steve Wenke		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Clement Ma		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock	Jeffrey Watkins	Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Comments Submitted
5	Bonneville Power Administration	Francis Halpin		Negative	Comments Submitted

5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Calpine Corporation	Hamid Zakery		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City and County of San Francisco	Daniel Mason		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City of Redding	Paul Cummings	Bill Hughes	Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle	Kelly Silver	Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Abstain	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Dynegy Inc.	Dan Roethemeyer		Abstain	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		None	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		None	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann		None	N/A
5	Great Plains Energy - Kansas City Power	Harold Wyble	Douglas Webb	Negative	Comments Submitted

	and Light Co.				
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		None	N/A
5	Kissimmee Utility Authority	Mike Blough		Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Abstain	N/A
5	Lower Colorado River Authority	Wesley Maurer		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Abstain	N/A
5	OGE Energy - Oklahoma Gas and	Leo Staples		Affirmative	N/A

	Electric Co.				
5	Oglethorpe Power Corporation	Teresa Czyz		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Abstain	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Abstain	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	SCANA - South Carolina Electric and Gas Co.	Henry Delk		None	N/A
5	Seattle City Light	Mike Haynes		Negative	Comments Submitted
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tennessee Valley Authority	Brandy Spraker	Dennis Chastain	None	N/A
5	Tri-State G and T	Mark Stein		Abstain	N/A

	Association, Inc.				
5	U.S. Bureau of Reclamation	Erika Doot		Affirmative	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		None	N/A
5	Xcel Energy, Inc.	David Lemmons		Abstain	N/A
6	AEP - AEP Marketing	Edward P Cox		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Bonneville Power Administration	Alex Spain		Negative	Comments Submitted
6	City of Redding	Marvin Briggs	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	None	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston	Kelly Silver	Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Earle Saunders		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		None	N/A

6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	None	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		None	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	Platte River Power Authority	Carol Ballantine		Abstain	N/A
6	Portland General Electric Co.	Adam Menendez		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Abstain	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		None	N/A

6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Abstain	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity	Steven Rueckert		None	N/A

	Coordinating Council				

Previous 1 Next

Showing 1 to 297 of 297 entries

Comment Report

Project Name:	2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS) | PRC-012-2
Comment Period Start Date:	2/3/2016
Comment Period End Date:	3/18/2016
Associated Ballots:	2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes PRC-012-2 AB 3 ST 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes PRC-012-2 Non-binding Poll AB 3 NB

There were 43 sets of responses, including comments from approximately 41 different people from approximately 39 companies representing 8 of the Industry Segments as shown in the table on the following pages.

Questions

1. PRC-012-2: Requirements R4 and R6, Attachments 1 and 2, and the Supplemental Material section of the standard were modified for clarity and completeness. Do you agree with the proposed changes? If no, please provide the basis for your disagreement and an alternate proposal.

2. Implementation Plan for PRC-012-2: The drafting team revised the Implementation Plan to provide for the initial consideration of limited impact RAS, and to clarify that the initial obligation under Requirement R9 for a Reliability Coordinator that does not have a RAS database is to establish a RAS database by the effective date of PRC-012-2. Do you agree with the revised Implementation Plan? If no, please provide the basis for your disagreement and an alternate proposal.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Ben Engelby	6		ACES Standards Collaborators - PRC-012-2 Project	Ellen Watkins	ACES Power Marketing	1	SPP RE
					Shari Heino	ACES Power Marketing	1,5	Texas RE
					Ginger Mercier	ACES Power Marketing	1,3	SERC
					Mark Ringhausen	ACES Power Marketing	3,4	RF
					Caitlin Schiebel	ACES Power Marketing	4	RF
					John Shaver	ACES Power Marketing	1,4,5	WECC
					Bill Hutchison	ACES Power Marketing	1	SERC
					Scott Brame	ACES Power Marketing	3,4,5	SERC
					Chip Koloini	ACES Power Marketing	5	SPP RE
					Bill Hutchison	ACES Power Marketing	1	SERC
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	SPP RE	SRC-ISONE	Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	SPP RE
					Ben Li	Southwest Power Pool, Inc. (RTO)	2	NPCC
					Ali Miremadi	Southwest Power Pool, Inc. (RTO)	2	WECC
					Greg Campoli	Southwest Power Pool, Inc. (RTO)	2	NPCC
					Liz Axson	Southwest Power Pool, Inc. (RTO)	2	Texas RE
					Lori Spence	Southwest Power Pool, Inc. (RTO)	2	MRO
					Mark Holman	Southwest Power Pool, Inc. (RTO)	2	RF

Public Service Enterprise Group	Christy Koncz	1,3,5,6	NPCC,RF	PSEG	Tim Kucey	Public Service Enterprise Group	5	RF
					Karla Jara	Public Service Enterprise Group	6	RF
					Joseph Smith	Public Service Enterprise Group	1	RF
					Jeffrey Mueller	Public Service Enterprise Group	3	RF
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
SERC Reliability Corporation	David Greene	10	SERC	SERC DRS	Mei Li	SERC Reliability Corporation	1	SERC
					Zakia El Omari	SERC Reliability Corporation	1	SERC
					Wade Richards	SERC Reliability Corporation	1	SERC
					Bob Jones	SERC Reliability Corporation	1	SERC
					John O'Connor	SERC Reliability Corporation	1	SERC
					John Sullivan	SERC Reliability Corporation	1	SERC
					Tom Cain	SERC Reliability Corporation	1	SERC
					Venkat Kolluri	SERC Reliability Corporation	1	SERC
MRO	Emily Rousseau	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Joe Depoorter	MRO	3,4,5,6	MRO
					Chuck Lawrence	MRO	1	MRO
					Chuck Wicklund	MRO	1,3,5	MRO

					Dave Rudolph	MRO	1,3,5,6	MRO
					Kayleigh Wilkerson	MRO	1,3,5,6	MRO
					Jodi Jenson	MRO	1,6	MRO
					Larry Heckert	MRO	4	MRO
					Mahmood Safi	MRO	1,3,5,6	MRO
					Shannon Weaver	MRO	2	MRO
					Mike Brytowski	MRO	1,3,5,6	MRO
					Brad Perrett	MRO	1,5	MRO
					Scott Nickels	MRO	4	MRO
					Terry Harbour	MRO	1,3,5,6	MRO
					Tom Breene	MRO	3,4,5,6	MRO
					Tony Eddleman	MRO	1,3,5	MRO
					Amy Casucelli	MRO	1,3,5,6	MRO
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Dana Wheelock	Seattle City Light	3	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,3,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Robert A. Schaffeld	Southern Company - Southern Company Services, Inc.	1	SERC
					R. Scott Moore	Southern Company - Southern Company Services, Inc.	3	SERC

					William D. Shultz	Southern Company - Southern Company Services, Inc.	5	SERC
					John J. Ciza	Southern Company - Southern Company Services, Inc.	6	SERC
Dominion - Dominion Resources, Inc.	Randi Heise	5		Dominion - RCS	Larry Nash	Dominion - Dominion Resources, Inc.	1	SERC
					Louis Slade	Dominion - Dominion Resources, Inc.	6	SERC
					Connie Lowe	Dominion - Dominion Resources, Inc.	3	RF
					Randi Heise	Dominion - Dominion Resources, Inc.	5	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC No HQ and Dominion	Paul Malozewski	Northeast Power Coordinating Council	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Brian Shanahan	Northeast Power Coordinating Council	1	NPCC
					Rob Vance	Northeast Power Coordinating Council	1	NPCC
					Mark J. Kenny	Northeast Power Coordinating Council	1	NPCC
					Gregory A. Campoli	Northeast Power	2	NPCC

	Coordinating Council		
Randy MacDonald	Northeast Power Coordinating Council	2	NPCC
Wayne Sipperly	Northeast Power Coordinating Council	4	NPCC
David Ramkalawan	Northeast Power Coordinating Council	4	NPCC
Glen Smith	Northeast Power Coordinating Council	4	NPCC
Brian O'Boyle	Northeast Power Coordinating Council	5	NPCC
Brian Robinson	Northeast Power Coordinating Council	5	NPCC
Bruce Metruck	Northeast Power Coordinating Council	6	NPCC
Alan Adamson	Northeast Power Coordinating Council	7	NPCC
Michael Jones	Northeast Power Coordinating Council	3	NPCC
Michael Forte	Northeast Power Coordinating Council	1	NPCC
Kelly Silver	Northeast Power Coordinating Council	3	NPCC

					Brian O'Boyle	Northeast Power Coordinating Council	5	NPCC
					Edward Bedder	Northeast Power Coordinating Council	1	NPCC
					David Burke	Northeast Power Coordinating Council	3	NPCC
					Peter Yost	Northeast Power Coordinating Council	4	NPCC
					Helen Lainis	Northeast Power Coordinating Council	2	NPCC
					Michele Tondalo	Northeast Power Coordinating Council	1	NPCC
					Kathleen Goodman	Northeast Power Coordinating Council	2	NPCC
					Silvia Parada Mitchell	Northeast Power Coordinating Council	4	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool, Inc. (RTO)	2	SPP RE
					Jason Smith	Southwest Power Pool, Inc. (RTO)	2	SPP RE
					Patrick McPhail	Southwest Power Pool, Inc. (RTO)	1	SPP RE
					Robert Hirchak	Southwest Power Pool, Inc. (RTO)	1,3,5,6	SPP RE
					Jamison Cawley	Southwest Power Pool, Inc. (RTO)	1,3,5	MRO

					Greg Hill	Southwest Power Pool, Inc. (RTO)	1,3,5	MRO

1. PRC-012-2: Requirements R4 and R6, Attachments 1 and 2, and the Supplemental Material section of the standard were modified for clarity and completeness. Do you agree with the proposed changes? If no, please provide the basis for your disagreement and an alternate proposal.

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RF	
Answer	No
Document Name	
Comment	
We object to Generator Owners having a primary role in this standard. The nature of a RAS is not to protect individual generators, for these must have adequate protection for faults or abnormal operating situations. The RAS is typically designed to maintain the reliability of a significant area of the overall power system. As such, the Transmission Owner is the best entity to ensure that RAS are employed correctly. Unlike the GO, the TO has the "wide-area" scope of monitoring and system responsibility. The draft standard is deficient due to the patchwork nature of responsibility for a RAS, especially when there are multiple Owners of portions of the RAS. There needs to be a single RAS Owner that has overall responsibility for ensuring the requirements of PRC -01 should be a Transmission Owner, not a Generator Owner. The TO (RAS Owner) should take the lead in developing the data needed for requirements R1 and R3, with the other RAS entities being required to provide data and equipment modifications as needed. Requirements R5 through R8 should apply to the RAS-Owner, not the RAS entities. The RAS Owner should be the point of contact with the Planning Coordinator/Reliability Coordinator, with the RAS entities having responsibility to collaborate with the RAS Owner as needed.	
Likes 1	U.S. Bureau of Reclamation, 5, Doot Erika
Dislikes 0	
Response	

Daniel Mason - City and County of San Francisco - 5	
Answer	No
Document Name	
Comment	
The Standards identifies a RAS-entity as "the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS". In some cases this "part" could be as limited as a sensing device providing input to another entity's RAS logic and interupting devices. For those RAS-entities that find themselves in that situation, providing the information identified in Attachments 1 and 2 is not appropriate. The Standard should clear up reporting responsibilities for such minor RAS-entities, perhaps by employ the concept of a "RAS Reporting Agent" for each RAS.	
Likes 0	
Dislikes 0	
Response	

Gul Khan - Gul Khan	
Answer	No
Document Name	
Comment	
Oncor does not currently provide the documents mentioned on page 21 of the PRC-012-2 draft 3 standard bullet # 1. We can provide a simple map of where a RAS will be located but if we are being requested to provide relay functional drawings or detailed 3 line schematics we won't have those drawings developed until the RAS is approved. Additionally even if we have the documents and do send it to ERCOT, we have a confidentiality concern as these files will get posted in a public information database. We have touched base with our RC, ERCOT, and they agree that the process we are doing today is satisfactory and is working. Hence we do not see a need to provide the documentation in attachment 1. The additional information should be optional.	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP appreciates the efforts of the SDT and recommends the removal of the language in the attachments that refers to a "checklist". Initial drafts of the attachments were checklists. What is presented cannot be described as a "checklist". SRP believes this language will create confusion. SRP further recommends removing the definition for "limited impact" from the footer of the attachment. If this is to be a definition, it should be defined in the NERC Glossary of Terms. SRP recommends the removal of the definition for "Functionally Modified" from the footer of the documents. Capitalized terms are to be part of the NERC Glossary of Terms and should not be located outside of that body of work.	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	No
Document Name	

Comment	
AZPS appreciates the efforts of the Standard Drafting Team (SDT) to date and makes the following comments: The materials state that a limited impact RAS is “determined by the RC”. AZPS suggests modifying the language to “…limited impact RAS as determined by the RC based on predefined regionally appropriate criteria.” An RC's determination of whether a RAS is limited impact should include an evaluation of the potential impacts of the RAS and should reference pre-defined regionally appropriate criteria defined through a regionally accepted process (e.g. via the RASRC in WECC). The Technical Justification section directed to Limited Impact states, “The reviewing RC is the sole arbiter for determining whether a RAS qualifies for the limited impact designation.” While not in direct conflict, AZPS believes that some entities may misinterpret the modified language as limiting the “The RC from requesting assistance in RAS reviews from other parties such as the PC(s) or regional technical groups (e.g., Regional Entities)” as provided for earlier in the document. AZPS requests that the “sole arbiter” sentence be clarified to address this concern. R4.1.3 is currently amended to state “for limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.” The word “contribute” should be removed because it reduces clarity to the standard. The term “contribute” is too broad and creates challenges to precisely evaluate. AZPS appreciates the DT addressing the concern of cases where a RAS crosses one or more RC Area boundaries, each affected RC is responsible for conducting either individual reviews or participating in a coordinated review by adding language in the appropriate rational and Supplemental Material sections. AZPS requests the SDT consider if this information would be more impactful as a footnote to the requirements themselves.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	Project 2010-05 3 PRC-012-2L RAS Seattle City Light Comments Ballot 2016 March 16.pdf
Comment	
Need to clarify roles and responsibilities for those RAS that are multi-jurisdictional. See Attached comments	
Likes 0	
Dislikes 0	
Response	
Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	No
Document Name	PSEG Comments_2010-05.3_3-17-2016.doc
Comment	

Requirement 1 – There are no clear lines of responsibility for jointly owned RASs.

The concept of a RAS-entity causes RAS-entity causes confusion for entities that have joint ownership of a RAS. While the SDT recognizes this issue by stating: “ Ideally, when there is more than one RAS -entity for a RAS, the RAS -entities w Attachment 1to the reviewing RC”. While PSEG agrees with the intent of this statement, it is included in the “Rationale” section of the draft standard and therefore that language will not be incorporated into the final standard. Furthermore, PSEG believes that PSEG that the language of R1 would still require each RAS entity to submit all information in Attachment 1to the Reliability Coordinator, which is inconsistent with the Paragraph 81 effort and the Reliability Assurance Initiative. PSEG believes such intent could be incorporated in to R1 as follows:

R1. Prior to placing a new or functionally modified RAS in the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. If there are multiple RAS-entities, the entities may delegate a single mutually agreeable RAS-entity to submit Attachment 1 on their behalf.

PSEG wishes to note that such language would not be useful in situations where the one or more of the RAS-entities that jointly own a RAS do not want to cooperate or cannot agree upon a single lead entity. Additionally, PSEG believes that a single entity (either the Reliability Coordinator or the Planning Coordinator) should be responsible for coordinating the RAS entities.

Attachment 1 – Attachment 1 should have defined roles for the Planning Coordinator (PC) or Transmission Planner (TP).

Since the requirement for new and revised remedial action schemes are likely to be initiated by the results of Transmission system planning performance assessments done by the TP or PC in compliance with TPL-001-4, one of those entities would be best suited to perform many of the activities listed under section II of Attachment 1.

Furthermore, the technical studies that are required by Attachment 1 should not be performed individually by each RAS-entity because they do not have the skills or tools available to perform such analyses. For example, if an independent generator is asked by its RC to implement a run-back scheme to resolve a stability issue, it is unlikely that that entity would have to tools available to provide the information required under Attachment 1, item II.6.

Rather, PSEG recommends that the RAS-entities’ PC or (TP) conduct the assessment of the System performance of a proposed new, modified, or retired RAS. Under this construct a RAS-entity implementing a new, modified, or retired RAS would submit an application under R1 containing general information as well as details concerning the proposed components and logic of the RAS to its TP or PC and to other RAS-entities that would participate in the RAS The PC or TP in turn would conduct the assessment of the proposed RAS to determine if the proposed RAS resolves the System performance issues, and forward that information to the RC for consideration under Requirement 2.

Likes 2	Pragna Pulusani, N/A, Pulusani Pragna; PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
Dislikes 0	

Response

Greg Davis - Greg Davis

Answer	No
Document Name	

Comment

GTC Background:

There are multiple registered Planning Coordinators and jointly shared transmission system in GTC's Planning Area and it is important for each PC in the area to be notified prior to placing new or functionally modified RAS in-service or retiring an existing RAS. Equally as important, is for each PC in the area to be notified if CAP actions or timetables change when the CAP is completed pursuant to CAPs developed for R6. GTC's proposed considerations listed below are focused on mitigating operational and compliance risks associated with awareness and knowledge of new or functionally modified RAS where there are multiple registered PCs in a common RC Area.

R7.3:

Although R4.2 requires each impacted TP and PCs to be notified of results of a RAS evaluation, there is not a similar method for any impacted TP and/or PC to be notified in which a RAS was evaluated with identified deficiencies pursuant to CAPs developed for R6; nor when or if CAP is implemented in a timely manner or if timetables change. We propose including the phrase "and Planning Coordinators within the RAS-entity's area" in R7.3, which would read as follows: "Notify each reviewing Reliability Coordinator and Planning Coordinators within the RAS-entity's area, if CAP actions or timetables change and when the CAP is completed."

R9:

Even though it seems implied in R9 that the RAS database containing all pertinent data will be made available to impacted PCs and/or TPs in the RCs area, it is unclear. GTC proposes the following new requirement to compliment the obligations of the Planning Coordinator under requirement R4 if the aforementioned proposed changes to R7.3 are not adopted by the SDT.

R10 (proposed new requirement): Each Reliability Coordinator shall provide each Planning Coordinator in their Reliability Coordinator area a copy of the RAS database maintained in accordance with R9, at least once every twelve full calendar months.

R4.1.5:

Since a RAS is only required when the performance requirements of TPL-001-4 will not be met, is R4.1.5 essentially mandating redundancy for all RAS components? What does a single component failure constitute under Requirement R 4.1.5?

Clarification of limited impact RAS:

SERC DRS suggests a revision as to what constitutes a limited impact RAS. Currently, the language in the standard suggests that an RAS considered to be limited impact cannot:

"cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations"

We suggest revising the above language by inserting the term "widespread" before angular instability. Angular instability could be experienced by just one generating unit going out of sync. A single generating unit becoming unstable is not indicative of an unstable or unreliable BES, and we do not believe that this should remove an RAS from limited impact consideration.

Likes 0	

Dislikes 0	
Response	
Ben Engelby - ACES Power Marketing - 6, Group Name ACES Standards Collaborators - PRC-012-2 Project	
Answer	No
Document Name	
Comment	
1. RAS-entity causes confusion for entities that have joint ownership of a RAS. We recommend the SDT develop guidance to support the requirements and expectations for joint owners to meet compliance. For RAS with multiple RAS-entities, who is responsible for overall coordination to assure complete and consistent data submittals in order to meet compliance with this standard? 2. For R2, we remain concerned by the term "mutually agreeable" and how it will be applied. 3. Why did the SDT give the RC the authority to determine "limited impact" RAS without providing objective criteria or guidelines? The SDT cited Local Area Protection Scheme (LAPS) in WECC and the Type 3 designation in NPCC. What about the other regions? There should be a specific set of parameters for the RC to make a decision. We suggest developing continent-wide criteria for determining limited impact RAS and not referring to only two regional approaches. 4. Why does the SDT include "limited impact" RAS as being applicable to the standard? If it has a limited impact, then it should not apply at all. This proposal by the SDT is contrary to the past two years of NERC's RAI and RBR initiatives focusing on HIGH RISK activities. By definition, "limited impact" should not matter for BES reliability. The limited impact designation creates unnecessary compliance burdens without a clear benefit to increased reliability of the BES.	
Likes 0	
Dislikes 0	
Response	
Teresa Czyz - Oglethorpe Power Corporation - 5	
Answer	No
Document Name	
Comment	
OPC agrees with GTC's comments: There are multiple registered Planning Coordinators and jointly shared transmission system in GTC's Planning Area and it is important for each PC in the area to be notified prior to placing new or functionally modified RAS in-service or retiring an existing RAS. Equally as important, is for each PC in the area to be notified if CAP actions or timetables change when the CAP is completed pursuant to CAPs developed for R6. GTC's proposed considerations listed below are focused on mitigating operational and compliance risks associated with awareness and knowledge of new or functionally modified RAS where there are multiple registered PCs in a common RC Area. **R7.3:** Although R4.2 requires each impacted TP and PCs to be notified of results of a RAS evaluation, there is not a similar method for any impacted TP and/or PC to be notified in which a RAS was evaluated with identified deficiencies pursuant to CAPs developed for R6; nor when or if CAP is implemented in a timely manner or if timetables change. We propose including the phrase "and Planning Coordinators within the RAS-	

entity's[JSS1] area" in R7.3, which would read as follows: "Notify each reviewing Reliability Coordinator and Planning Coordinators within the RAS-entity's area, if CAP actions or timetables change and when the CAP is completed."

R9:

Even though it seems implied in R9 that the RAS database containing all pertinent data will be made available to impacted PCs and/or TPs in the RCs area, it is unclear. GTC proposes the following new requirement to compliment the obligations of the Planning Coordinator under requirement R4 if the aforementioned proposed changes to R7.3 are not adopted by the SDT.

R10 (proposed new requirement): Each Reliability Coordinator shall provide each Planning Coordinator in their Reliability Coordinator area a copy of the RAS database maintained in accordance with R9, at least once every twelve full calendar months.

R4.1.5:

Since a RAS is only required when the performance requirements of TPL-001-4 will not be met, is R4.1.5 essentially mandating redundancy for all RAS components? What does a single component failure constitute under Requirement R 4.1.5?

Clarification of limited impact RAS:

SERC DRS suggests a revision as to what constitutes a limited impact RAS. Currently, the language in the standard suggests that an RAS considered to be limited impact cannot:

"cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations"

We suggest revising the above language by inserting the term "widespread" before angular instability. Angular instability could be experienced by just one generating unit going out of sync. A single generating unit becoming unstable is not indicative of an unstable or unreliable BES, and we do not believe that this should remove an RAS from limited impact consideration.

Likes 0	
Dislikes 0	

Response

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1

Answer	No
Document Name	

Comment

Requirement 4 of the standard puts the burden of performing the studies on the PC. PNM as a registered PA/PC doesn't contest the assignment of the requirement to the PC; however, the standard doesn't guarantee that the PC will be provided with the data required to perform the assessment. PNM proposes adding a requirement for the RAS entity to provide data required to assess the RAS within 30 calendar days of receiving approval from the RC

so that the PC can obtain the information required to adequately assess each scheme every five full calendar years. The information provided to the RC in R5.2, R6, R7.3 would impact the R4 assessment; therefore, the PC should also be receiving this information.	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1	
Answer	No
Document Name	
Comment	
What is the required evaluation for the PC in R4? For the RC it is clear to follow Attachment 2 for the evaluation but the PC in R4 does not have any explicit evaluation requirement. We recommend adding language that describes the PC adhering at a minimum, but not limited to, Attachment 2 for their 5 year evaluation. Both R4.1.4 and Attachment 1, section III, item 4 use the same language, "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 required for the events and conditions for which the RAS is designed." Though similar language is used in the currently effective set of reliability standards, it is confusing and unclear. We recommend providing examples in an application guideline as part of the standard itself that might help the reader understand the meaning of and intent behind this language.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy suggests a revision as to what constitutes a limited impact RAS. Currently, the language in the standard suggests that an RAS considered to be limited impact cannot: *"cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations"*	

We suggest revising the above language by inserting the term “widespread” before angular instability. Angular instability could be experienced by just one generating unit going out of sync. A single generating unit becoming unstable is not indicative of an unstable or unreliable BES, and we do not believe that this should remove an RAS from limited impact consideration.

Duke Energy also reiterates its concern regarding the compliance implications of potentially requiring the RC to be responsible for the technical correctness of an RAS-entity’s information it provides in Attachment 1. An RC should only be held responsible for the “wide area purview” or conceptual appropriateness of a new or functionally modified RAS, and not be held responsible for potential mistakes made by the RAS-entity during the process.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment

Would suggest the drafting team develop a Standards Authorization Request (SAR) for the term ‘limited impact’ and propose the term be added to the NERC Glossary and Rules of Procedure (RoP) to promote consistency and clarity. During our current evaluation of this draft of the Standard and RSAW, we are concerned that the Rationale Box information (page 5 of the Standard-next to the sentence) is not consistent with the Requirement R4 sub-part 4.1.3. Another concern is that we feel the sub-part states the proposed definition of ‘limited impact’ twice. At the first use, the term ‘limited impact’ is stated with a footnote-4 “A RAS designated as ‘limited impact’ cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations” then this same information is stated again after the term. We suggest the drafting team use some different language besides “verify the limited impact designation remains applicable” which was stated in the Rationale Box in order to make it clear just what the SDT intends the reviewer to do.

Additionally, we interpret that in the RSAW (note to Auditor-Section Requirement R4) there is an attempt to define the term ‘Inadvertent operation’. If this is the case, we would suggest the review panel/drafting team should develop a SAR for that particular term and propose that it be included in the NERC Glossary of Terms and Rules of Procedure (RoP) as well as including that term in the Standard again to promote consistency and clarity.

For Requirement R6, we have a concern that the translation of the Rationale and Technical data (in the Standard) and the Note to Auditor information (in the RSAW) may become lost. As we have evaluated both documents, it seems more evident that the Rationale and Technical information needs to be included in the RSAW. This information has been included in the Standard to help provide a solid foundation to each Requirement to help support the auditing process. However, this information isn’t included in the RSAW which leads to potential inconsistency in the auditing process. We feel that both documents need to contain the same information in order to be properly aligned.

Finally, our last concern would be having all maintenance requirements implemented into one document. Currently, we agree that Requirement R8 pertains to performing maintenance associated with Functional Testing as well as verifying proper operation of non-protection system components (system maintenance). However, we suggest moving Requirement R8 into the PRC-005 Standard for consistency in reference to maintenance requirements.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
The list of qualifications for the designation of limited impact states that a limited impact RAS cannot cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. The term angular instability needs to be clarified further. Currently it implies that if the RAS was installed to prevent a 40 MW generator from becoming unstable, then it cannot be designated as limited impact. The term should be qualified as follows: system angular instability. This would give the RC the leeway to judge that a small unit going unstable would not negate the designation limited impact.	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

ERCOT is supportive of the "limited impact" RAS designation, and is also supportive of a periodic evaluation of RAS to determine if these still qualify for the limited impact designation. However, ERCOT disagrees with the language of requirement subpart 4.1.3.

Clarification on the intention of 4.1.3 in this context is requested. A Planning Coordinator (PC) with limited impact RAS (ex. a RAS set up to reduce BES flows by ramping down or tripping generation) should be allowed discretion to utilize screening studies as a threshold test to determine the necessity of evaluating a RAS for uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. For limited impact RAS that only have local impacts, 4.1.3 as written requires costly and unnecessary studies. ERCOT suggests that the SDT consider imposing a MW threshold for each interconnection below which the PC would be required to conduct only a power flow study. Alternatively, ERCOT requests clarification—in either 4.1.3 itself or in the rationale—that the PC has discretion in the type of studies it can use to satisfy the evaluations required to determine if the reliability impact of the RAS has changed over time.

ERCOT also asks for clarification on the "Supporting Documentation for RAS Review" in Attachment 1. The introductory statement in Attachment 1 implies that the Reliability Coordinator (RC) has discretion in determining exactly what information it would like to receive from an RAS-entity with the statement "If an item on this list does not apply to a specific RAS, a response of "Not Applicable" for that item is appropriate." The RAS-entity and the RC typically work together to determine what is required to approve an SPS or a RAS. The RC's discretion in determining what information a RAS-entity must submit under Attachment 1 is sufficient for the evaluation of the RAS.

ERCOT suggests the SDT make the RC's discretion explicit through the following language modification to the Attachment 1 introduction:

“The following checklist identifies important Remedial Action Scheme (RAS) information for each new or functionally modified RAS that the RAS-entity must document and provide to the reviewing Reliability Coordinator(s) (RC), *as required by the RAS-entity’s Reliability Coordinator*”	
Likes 0	
Dislikes 0	
Response	

Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	

ATC has several recommendations for improvement or clarification on the draft Standard, for consideration by the SDT as listed below:

- R4.1.3 and R4.1.4 – These requirements refer to ‘single component malfunction’ and ‘single component failure’ respectively. However, the standard does not contain any identification or clarification of which types of components must be included and which may be excluded in RAS evaluations. This deficiency could be addressed by including text in the Supplemental Material section under Requirement 4 that the drafting team developed for a response in its Consideration of Comments for Draft 1 of PRC-012-2.

“An exhaustive list of components is not practical given the variety that could be applied in RAS design and implementation. See Item 4a in the Implementation Section of Attachment 1 in the Supplemental Material section for typical RAS components for which redundancy may be considered. The RAS -entity should have a clear unde into service and which were already present in the system before a RAS was installed. The RC will make the final determination regarding which components should be regarded as RAS components during its review”.

- R5 – This requirement does not obligate RAS-entities to provide their results of the operational performance analysis of a RAS event to impacted Transmission Planners and Planning Coordinators. However, this action should be proposed in the Supplemental Material section.

- R6 – This requirement does not obligate RAS-entities to provide their Corrective Action Plans to impacted Transmission Planners and Planning Coordinators. However, this action should be proposed in the Supplemental Material section.

- R8 - The purpose of Version 6 of PRC-005 was to consolidate all maintenance and testing of relays under one Standard. Having RAS testing within PRC-012-2 would be contrary to that end. ATC proposes to address this concern as follows:

Functional testing of RAS (as stated in Requirement 8 of PRC-012-2) is a maintenance and testing activity that would be better included in the PRC-005 standard. The present PRC-005-6 Reliability Standard is the maintenance standard that replaces PRC-005-1, 008, 011 and 017 and was designed to cover the maintenance of SPSs/RASs. However, the current Reliability Standard PRC-005-6 lacks intervals and activities related to non-protective devices such as programmable logic controllers. ATC recommends that a requirement for maintenance and testing of non-protective RAS components be added to a revision of PRC-005-6, rather than be an outlying maintenance requirement located in the PRC-012-2 Standard.

If the requirement is not removed and placed in PRC-005 standard, then we suggest that wording be added to R8 to refer the entity to meet the maintenance and testing interval obligations in the latest version of the PRC-005 standard.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb

Answer	No
Document Name	

Comment

Kansas City Power & Light Company appreciates this opportunity to share its comments regarding concerns the company has with the proposed revisions to the Standard.

As used in the proposed revisions to Standard PRC-012-2, the term "limited impact" creates an ambiguous enforceable provision and needs to be a defined NERC Glossary term to establish a clear compliance threshold.

The Standard Drafting Team (SDT) is empowered by the NERC Standards Process Manual (SPM) to "…propose to add, modify, or retire a defined term in conjunction with the work it is already performing." SPM, Sec. 5 Preamble. We respectfully request the SDT exercise that authority to define "limited impact" for the following reasons.

"Limited impact" establishes an enforceable provision: The proposed revisions use "limited impact" in the language of the Requirements and attachments to the Standard that are incorporated by reference. By the regular use of the term, and the context in which it is used, a conclusion is easily drawn: The term is material to the Standard and required to evaluate compliance and, ultimately, enforcement of the Standard.

"Limited impact" creates an uncertain compliance obligation: The term "limited impact" is undefined and ambiguous and, as such, creates uncertainty in an entity's compliance obligation. The word "limited" suggests a range of values. When used with "impact," the range of values is used to affect the determination of the degree of impact. The proposed revisions to the Standard seek to establish the range of values in multiple ways. First, by referencing information found in the stated underlying source of the term, WECC and NPCC classification schemes; secondly, offering an explanation what is intended by the term; third, explaining what the term is not intended to reflect; and, lastly, a lengthy discourse on the term, as found in the Attachments. Taken together, all the information may seem to provide guidance as to the meaning of the term, "limited impact," but in the end the term remains undefined and creates a compliance obligation that is unclear and promotes a spectrum of interpretations as to what values fall within the "limited" range.

Policy promotes relevant Regional Defined Terms be considered for the NERC Glossary Term: The NERC Standards Process Manual (SPM) states:

"Some NERC Regional Entities have defined terms that have been approved for use in Regional Reliability Standards, and where the drafting team agrees with a term already defined by a Regional Entity, the same definition should be adopted if needed to support a NERC Reliability Standard." SPM Sec. 5.1.

The proposed revisions to the Standard provide that the source of the term "limited impact" is taken from the WECC and NPCC classification schemes. Whether the term is a regionally defined term by WECC and NPCC or not, the spirit of the SPM is to apply terms equally, that if a term is used by

Regional Entities in a North American Standard, then it is appropriate for the term be considered for adoption as a defined term to support that Standard.

Below is a Catalog of the Term "limited impact" as used in Proposed PRC-012-2 Standard

The Standard's language uses "limited impact" in Requirements R4 and R8, and multiple times in the three attachments that are incorporated by reference in the Standard.

WECC and NPCC Classification Schemes—R4 Rationale cites to the WECC and NPCC classification schemes as how the "…limited impact designation is modeled…;" *Technical Justification* for the term "limited impact" states, "Because the drafting team modeled the limited impact designation after the WECC and NPCC classifications…"

Description of what the term, "limited impact," is not—R4.1.3. Footnote to "limited impact." See also Att. 1, Sec. I.4.g Footnote to "limited impact"; Att. 2, Sec. I.6 Footnote to "limited impact"; Att. 3, Sec. 7 Footnote to "limited impact"; *Technical Justifications for Attachment 1 Content Supporting Documentation for RAS Review*, Sec. I.4.g Footnote to "limited impact"; *Technical Justifications for Attachment 3 Content*, Sec. 7 Footnote to "limited impact."

"Limited impact" Citations in Standard—The use of the term "limited impact" in R4; R8; Att. 1, Sec. I.4.g; Att. 1, Sec. II.5; Att. 1, Sec. II.6; Att. 1, Sec. III.4; Att. 2, Sec. I.6; Att. 2, Sec. I.7; Att. 2, Sec. II.2; Att. 3, Sec. 7; *Supplemental Material*, R4, R8; *Technical Justifications for Attachment 1 Content Supporting Documentation for RAS Review*, Sec. I.4.g, Sec. II.5, Sec. II.6, Sec. III.4; and *Technical Justifications for Attachment 3 Content*, Sec. 7.

Likes 0	
Dislikes 0	

Response

Oshani Pathirane - Oshani Pathirane

Answer	No
Document Name	

Comment

Comment 1 - R4.1.5 - In TPL-001-4, loss of a single line due to a fault is "Single Contingency" (Category P1), but the failure of a breaker or protection relay following that single contingency is recognized as "Multiple Contingency" (Category P4 and P5) and has a different performance requirement compared to the initial P1 event. Similarly, the system performance following a RAS failure to operate after an event should not be required to meet the exact same requirements as those for the original event.

Therefore, we suggest deleting 4.1.5 and instead revising 4.1.4 to say "Except for limited impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction, or a single component failure in the RAS, when the RAS is intended to operate, satisfies all of the following:"

Comment 2 - R5.1 – The wording "*participate*" which is used in the R5.1 does not define accountability or a definite action. For consistency, we suggest using verbiage similar to that used in PRC-004-4's description of accountabilities in the case of owning Shared Protection Systems.

Comment 3 - R5.1.3 & R5.1.4 are related to performance of RAS and its impact on BES system. This assessment is better suitable for the PC or RC to conduct

Comment 4 – In R5.2, in case of a RAS being owned by more than one RAS-Entity, it is unclear which RAS-Entity is accountable to communicate with the RC and maintain evidence. The requirement needs to clearly identify who is accountable for what, similarly to how PRC-004-4 describes accountabilities in case of Shared Protection System.

Comment 5 – Similar to R5, the wording "*participate*" used in R6 does not define accountability or a definite action. For consistency, we suggest using verbiage similar to that used in PRC-004-4's description of accountabilities in the case of owning Shared Protection Systems.

Comment 6 - Similar to comment R5 above, R6 does not clearly define accountabilities in the case of a RAS being owned by more than one RAS-Entity. In such case, which Entity is accountable to communicate with the RC and maintain evidences?

Comment 7 – It is unclear from the wording whether the RAS-entity would "Participate in analyzing the RAS operational performance" with the RC, or only mutually agree upon a schedule for such activity with the RC.

Comment 8 - R8 is vague and subject to interpretation. There are references in the supplemental material that suggest maintenance checking all of the logic in a PLC on a periodic basis is required and yet in PRC-005, it's clear that there is no need to perform periodic maintenance on relay logic. For monitored components, such as microprocessor relays, the "*verification of settings [as] specified*" in PRC-005 (i.e., performing a settings compare) should be sufficient rather than implying that all logic needs to be re-verified. For RAS not designated as limited-impact, R8 does not distinguish between monitored and unmonitored components of the RAS such as in PRC-005, which would allow a RAS-entity to have a 12-year maintenance interval for monitored components.

Likes 0	
Dislikes 0	

Response

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

Regarding R4:
BPA believes that limited impact RAS should not be singled out to be exempt from meeting the performance requirements.

While the level of review could be lower, BPA believes a "limited impact" RAS should still be designed such that failure or inadvertent operation of the RAS does not have an adverse impact on an adjacent TP or PC beyond the performance criteria for which the system is planned.

Additionally, regarding R2:
BPA maintains that allowing an RC up to four months to complete the RAS review is longer than necessary and not in line with current practice, which requires the information to be submitted to the RAS Reliability Subcommittee two weeks prior to the meeting where it will be reviewed and approved or disapproved. Allowing four months could delay energization of new or functionally modified RAS by 14 weeks.

BPA also remains concerned by the term "mutually agreeable" and how it will be applied.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	RS--3-15-16--2010-05 3_PRC-012-2_Unofficial_Comment_Form_2016-03-18- Final.docx
Comment	

As a general comment, HQT is in the view that PRC-012-2 should not address the details of how RAS entities should perform their analysis according to requirement R8. Each RAS entity has systems operation applicability adapted to their particular topology and some systems cannot withstand invasive actions (maintenance and testing activities) because of such topology. Therefore, PRC-012-2 requirements should allow a certain level of flexibility to this effect, which HQT has commented further below.

Regarding comments specific to the wording of PRC-012-2 requirements, Footnote 2 in Attachment 1 is a definition, and it should be treated as such. Also, the fourth bullet under footnote 2 reads “Changes to RAS logic beyond correcting existing errors” needs clarification. What are the existing errors? The RAS should not have been approved if there were errors, and if it was approved with the errors then those errors might be preventing the RAS from meeting its intended functionality. Suggest removing this bullet, and revising the second bullet to read: Changes to the logic that affects the actions the RAS is designed to initiate. The preceding is also applicable to Footnote 4 on page 25 for Attachment 2. Footnote 3 on page 23, footnote 5 on page 25, and footnote 6 on page 27 are not needed because of the first comment above regarding Requirement R4.

In addition, on page 27 in the Supplemental Material Section, shouldn’t the Planning Coordinator, because of its wide-area view be included in determining if a RAS can be designated limited impact? In the two paragraphs preceding Requirement R1 on page 29 of the Supplemental Material it should be emphasized that the actions of the limited-impact RAS do not lead to the more severe BES consequences that would preclude a RAS from being defined a limited-impact RAS. On page 34, same comment as in the preceding paragraph concerning “Changes to RAS logic beyond correcting existing errors”. On page 34 of the Supplemental Material in the third paragraph under Requirement R4, shouldn’t the Planning Coordinator, because of its wide-area view, be involved in the designation of a RAS as limited-impact?

Also, on page 45 for the Technical Justifications for Attachment 1 Content Supporting documentation for RAS Review, comments pertaining to footnote 8 the same as above for the comments regarding footnote 2.

HQT also has specific comments on requirements R5 and R8 as follows.

Firstly for NPCC, the Type ‘3’ should be written ‘III’. Also, VSL of R5 requests to ‘perform’ analysis. R5 mentioned only to ‘participate’. In the Rationale section, at R4: references to Parts 4.1.3.1-4.1.3.5 should be corrected to 4.1.4.1-4.1.5. HQT is in the opinion that Lower VSL of R7 should be High VSL because RC must be notified if CAP has changed since changes in action or timetables may require the RC to intervene to maintain reliability.

Secondly, HQT suggests to remove footnote 3 on page 23, footnote 5 on page 25, and footnote 6 on page 27 by modifying the Applicability section 4.2.1 in section 4.2 entitled Facilities by the following: ‘‘Remedial Action Schemes (RAS) not designated as “limited impact”. A RAS designated as “limited impact” cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.’’

Thirdly, regarding requirement R8, as mentioned in HQT’s general comments above, as for protection systems, invasive actions (maintenance and testing activities) may introduce a higher number of misoperations which can stress the electrical system. As recognized in PRC-005, new technology may offer the benefits to avoid this type of activities. Thus, from a reliability perspective, a RAS Entity should decide which technique is most appropriate to verify the RAS integrity according to the complexity of their design. If for some reason, a RAS entity would prefer to dynamically extract and compare the settings file of the RAS components instead of doing functional tests, it could be another acceptable method to meet the intent of requirement of R8 without doing invasive actions that could adversely affect the reliability of the system.

HQT notes that there is actually no difference made in PRC 005 for limited impact RAS components. However, HQT agrees with PRC 012-2 regarding the fact that limited impact RAS represents a low reliability risk to the BULK power system. For those RAS, HQT agrees that less stringent criteria can be applied. In PRC-005, there is no mention of limited impact RAS components, this concept should be incorporated within the standard.

Finally, in light of the above comments, HQT is of the view that the maximum allowable interval between functional tests should be twelve full calendar years for RAS that are not designated as limited impact RAS.	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Larry Heckert	
Answer	Yes
Document Name	
Comment	
Alliant Energy supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6	
Answer	Yes
Document Name	
Comment	
In the Supplemental Material, on p. 30 of 55 of the redlined document, please clarify what is meant by "…affected by the contingency." Specifically, is this the contingency that would require RAS operation, or is the contingency the overloading of the BES Element? Outside of the scope of the survey question -- in Measurement M5, please consider changing "…with participating RAS-entities and…" to "…with participating RAS-entities, if applicable, and…"	
Likes 0	
Dislikes 0	
Response	
David Greene - SERC Reliability Corporation - 10, Group Name SERC DRS	
Answer	Yes
Document Name	
Comment	

SERC DRS suggests a revision as to what constitutes a limited impact RAS. Currently, the language in the standard suggests that an RAS considered to be limited impact cannot:

"cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations"

We suggest revising the above language by inserting the term "widespread" before angular instability. Angular instability could be experienced by just one generating unit going out of sync. A single generating unit becoming unstable is not indicative of an unstable or unreliable BES, and we do not believe that this should remove an RAS from limited impact consideration.

The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Dynamics Review Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.

Likes 0	
Dislikes 0	

Response

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)

Answer	Yes
Document Name	

Comment

However, the NSRF proposes including the following opinion in the Supplemental Material section:

R4 – This requirement refers to 'single component malfunction' and 'single component failure'. However, the standard does not contain any qualification of which types of components must be included in RAS evaluations or what entity ultimately makes the component inclusion determination. Therefore, to avoid making elaborate component inclusion qualifications or letting there be uncertainty over which entity makes the final component inclusion determination, add text to the Supplemental Material section such as, "The RC will make the final determination regarding which RAS components are included in the RAS evaluation during its review".

Likes 0	
Dislikes 0	

Response

William Temple - William Temple

Answer	Yes
Document Name	
Comment	
PJM supports the comments submitted by the ISO/RTO Council.	
Likes 0	
Dislikes 1	Public Service Enterprise Group , 1,3,5,6, Koncz Christy
Response	
John Pearson - John Pearson	
Answer	Yes
Document Name	
Comment	
Requirement R4.1.3 includes language from the associated footnote verbatim. The language in the footnote should be deleted. The requirement also seems to define a limited impact RAS. The NERC Glossary should include the definition of a limited impact RAS.	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
The Bureau of Reclamation agrees with the changes proposed by the drafting team.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No HQ and Dominion	
Answer	Yes
Document Name	

Comment	
Footnote 1 in Requirement R4 is not needed as written. It just reiterates the wording of sub 4.1.3. Same applies to footnote 9 on page 46 as the wording in sub 4.1.3 pertains to the entire document. An appropriate footnote would read that NPCC Type 3 classification and the WECC LAPS classifications will be recognized as limited-impact RAS.	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael DeLoach - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael DeLoach - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC-ISONE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	

Comment
Texas RE noticed the SDT did not specifically address its comments submitted on January 8, 2016. Texas RE respectfully requests the SDT to respond to its comments. As previously stated in comments submitted on January 8, 2016, Texas RE does not agree with the provision that a RAS can be designated as “limited impact”. Texas RE recommends the SDT reconsider and treat all RASes, that affect the reliability of the Bulk Electric System (BES) equally. However, if the SDT elects to keep the limited impact designation, Texas RE is concerned the proposed criteria for determining a “limited impact” RAS is vague and ambiguous (e.g. “… BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations). Absent clear criteria, the RC may designate certain RASes as limited impact that would be more properly characterized as a RAS. Because limited impact RASes are subject to reduced reliability-related considerations by the Reliability Coordinator (i.e. Attachment 2) and limited evaluation performed by the Planning Coordinator (i.e. Requirement 4), the improper characterization of RASes may lead to potential reliability gaps on the BES. Texas RE inquires as to what the SDT used as technical basis (such as industry reports, recommendations from task forces or working groups, field studies, etc) in determining to create a requirement to designate limited impact RASes. **TPL-001-4** In Requirement R4.1.5, Texas RE is concerned the planning requirements in TPL-001-4 do not distinguish between limited impact RAS and RAS. For example under TPL-001-4, a PC must consider an operation of a RAS, including a limited impact RAS, that results in an applicable Facility Rating being exceeded. Texas RE understands planning and RAS evaluation are separate obligations for the PC with separate requirements. However, the language in R4.1.5 specifically identifying the “same performance requirements” as defined in TPL-001-4 potentially blurs these two obligations with respect to limited impact RAS. Texas RE suggests eliminating the phrase “Except for limited impact RAS” in R4.1.5 so PRC-012-2 and TPL-001-4 cannot be interpreted to potentially conflict with each other. **Degraded RAS** Texas RE submitted comments on October 5, 2015 stating its concern there is no requirement to report the degraded RAS to the RC. The SDT responded: The status of a degraded RAS is required to be reported (in Real-time) to the Transmission Operator via PRC-001, Requirement R6, then to the RC via TOP-001-3, Requirement R8. See Phase 2 of Project 2007-06 for the mapping document from PRC-001 to other standards regarding notification of RC by TOP if a deficiency is found during testing. Consequently, it is not necessary to include a similar requirement in this standard. Texas RE does not agree this issue is handled in the standards identified by the SDT in its response. As an initial matter, TOP-001-3 R8 does not necessarily require the TOP to inform the RC. TOP-001-3 R8 is specifically limited to Emergencies, which do not necessarily include degradation of a RAS. Does the SDT envision treating all RAS degradations as Emergencies as defined by the NERC Glossary of Terms in order to trigger the TOP-001-3 R8 reporting obligations? TOP-001-3 also uses the term “Transmission Operator Area” which, by definition, does not necessarily include DP and GO, which are “RAS-entities”, equipment if used in a RAS. This is a gap in reliability.

In addition, other related standards do not appear to require RAS-entities to report degraded RASes to the RC in all circumstances. For example, TOP-003-3 discusses having a data specification and distributing the data specification. However, this Standard does not explicitly include notification of actual degradation of a RAS to an RC or explicitly require entities to provide actual data. In particular, TOP-003-3 R3 states "Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time RAS monitoring, and Real-time Assessment." Moreover, TOP-003-3 R3 explicitly covers the "Operations Planning" Time Horizon (not Real-time or Same-Day Operations). TOP-003-3 R5 also states "Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications…". Again, under this Standard, there is no explicit requirement that entities provide the RC that is reviewing and approving the RAS the actual data regarding the "current Protection System and Special Protection System status or degradation that impacts System reliability."

Misoperations

The definition of Misoperation that becomes effective on July 1, 2016 does not include RASes. Texas RE recommends clarifying R5 by defining misoperation to align with PRC-004-4. If misoperation is not defined, entities might not do the actions outlined in R 5.1. The SCPS drafted a RAS template to describe misoperations which were never officially approved. Texas RE recommends adding a definition of misoperations for RASes in the Standard or NERC Glossary based on the SCPS RAS template and the language in R5.

Also, while reporting of Protection Systems Misoperations will be contained within the Section 1600 Data Request for PRC-004, neither PRC-012-2 nor the Section 1600 data request provides a corresponding reporting requirement for RAS misoperations to the Regional Entities or NERC. Texas RE recommends the SDT consider adding a requirement, either to PRC-012-2 or to the Section 1600 data request, for Registered Entities to report misoperations of RASes to regional entities.

Functional Testing – R8

Texas RE is concerned PRC-012-2 R8 does not address the scenario where a RAS is owned by different companies. In particular, PRC-012-2 R8, as currently drafted, does not require simultaneous testing each separately-owned component of the RAS-system simultaneously so that entities can verify that the RAS properly operates. For example, there are instances in Texas where a GO and TO own part of the same RAS. Under the current Standard language, the GO will test the receipt signal and the TO will test sending signal. However, there is no requirement for the GO and TO to coordinate the tests of their individual components to ensure that signal is sent and received. Put differently, although each individual component may be tested, there is no corresponding test of to ensure the entire RAS will operate as intended. Texas RE is concerned a reliability gap will occur if the two tests are not conducted simultaneously and in such a way the GO and TO can view the results of the test on the entire RAS.

Full Calendar Months

The SDT introduces a new term "full calendar months" that is neither defined in the Standard nor the NERC Glossary and is inconsistent with other Reliability Standards. Texas RE noticed a definition in the PRC-012-2 RSAW, but the definition should be in the NERC Glossary or within PRC-012-2 itself instead. Texas RE recommends the SDT provide the definition within the Standards process while considering other definitions already in place (such as "Calendar Year" in PRC-005-6).

Corrective Action Plan

As previously submitted on January 8, 2015, Texas RE recommends revising PRC-12-2 R7 to place at least minimal criteria around modifications to Corrective Action Plans (CAP) or corresponding CAP timetables. As currently drafted, PRC-12-2 R7 could be interpreted to permit RAS-entities to perpetually update their CAPs if "actions or timetables change" and then merely notify the RC of such changes. Texas RE recommends that the SDT consider some minimal criteria that RAS-entities must satisfy in order to update a CAP under PRC-12-2 R7.2. For instance, PRC-12-2 R7.2 could be revised to read: "Update the CAP for any reasonable changes in the required actions or implementation timetable." In turn, PRC-12-2 R7.3 could be revised to read: “Notify each reviewing Reliability Coordinator and provide a reasoned justification for changes in CAP actions or timetables, and notify each reviewing Reliability Coordinator when the CAP is completed.”

Feedback Mechanism

Texas RE noticed there is no feedback mechanism in the current standard for PCs to incorporate RC approved RAS modifications in subsequent planning processes. Texas RE understands this might not appropriate for the scope of this project, but requests the SDT to consider this issue in future reviews of applicable standards.

Likes 0	
Dislikes 0	

Response

2. Implementation Plan for PRC-012-2: The drafting team revised the Implementation Plan to provide for the initial consideration of limited impact RAS, and to clarify that the initial obligation under Requirement R9 for a Reliability Coordinator that does not have a RAS database is to establish a RAS database by the effective date of PRC-012-2. Do you agree with the revised Implementation Plan? If no, please provide the basis for your disagreement and an alternate proposal.

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	RS--3-15-16--2010-05 3_PRC-012-2_Unofficial_Comment_Form_2016-03-18- Final.docx
Comment	
In light of the above comments, HQT is of the view that the maximum allowable interval between functional tests should be twelve full calendar years for RAS that are not designated as limited impact RAS.	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb	
Answer	No
Document Name	
Comment	
In consideration of our comments relating to the term “limited impact,” we are unable to support the Implementation Plan. The alternative proposal is incorporate into the Implementation Plan a future defined NERC Glossary term for “limited impact.”	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT signs on to the IRC SRC comments for Question 2. The SRC comments are as follows:	

•   The rationale for R2 states that RC review “minimizes the possibility of a conflict of interest that could exist because of business relationships among ….” This explanatory purpose for R2 is not needed and in fact could prove untrue as not all RCs are independent from TOs, GOs, etc.

•   The R3 rationale inserts the idea of “lack of dependability”. This can be understood differently by different parties. For a hardware supplier, it can mean the equipment or technology is unreliable. And if taken to an extreme, this seems to open the path to requiring the RC to decide which generators should run based on the individual generators’ forced outage rate (dependability rate?). We suggest this phrase be stricken from the R3 explanatory.

•   For R4 the limited impact designation explanation, please clarify whether the reference to regions is meant to be an example of how the SDT came to its decision for R4 or whether it is a reference of the authority of what regions can do. We believe it is the former and the language should be improved.

•   The concept of 4.1.2 to “avoid adverse interactions” would seem to need some criteria for evaluating what “avoid” means. Rather than state “avoid”, we suggest this requirement to be rewritten to state: “The RAS does not adversely impact the performance of other RAS, and protection and control systems.”

·   4.1.4.4. BES voltages shall be within post Contingency voltage lim tablished by the Transmission Planner and the Planning Coordinator. Some Planners don’t use voltage deviation criteria. This should it not be rewritten to state   “BES voltages shall be within the Planning Coordinator’s voltage criteria under pre and post contingency conditions”.

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Implementation Plan

Texas RE recommends reducing the implementation period. This is a series of processes that already exist in some form or fashion and should not require a new construct that would take three years. In Requirement R9, the SDT indicates requirements follow “industry practice” which is a twelve month periodicity. Does the SDT contend that there are RASes in place that an RC or PC does not know about?

Texas RE recommends that the SDT *eliminate the proposed implementation period or at least shorten the proposed three-year implementation period for PRC-12-2 to six months*. Alternatively, the SDT should link the 60-full-calendar month (currently revised to “5 full calendar years”) compliance window in PRC-12-2, R4 and the six- and twelve-year compliance periods in PRC-12-2, R8 to the effective date of PRC-12-2 and not the extended date (if any) set forth in the proposed implementation plan.

The proposed PRC-12-2 establishes a process for reviewing new, functionally modified, or retiring RAS. As the SDT has recognized, failing to implement such a RAS review process could result in a significant gap in reliability. Specifically, the SDT stated in the rationale for Requirement R1 that RAS “action(s) can have a *significant impact on the reliability and integrity of the Bulk Electric System (BES)*.” Given the importance of the RAS review scheme for reliability, Texas RE believes that three years is too long to implement the process contemplated in the proposed PRC-12-2.

Review Process Timeline

Texas RE also believes that the nature of the review process itself also counsels in favor of a shorter review period. For example, PRC-12-2, R1 – R3 establishes the basic framework for RAS review. These requirements mandate that RAS-entities provide certain information regarding RAS to their respective Reliability Coordinators (RC), a minimum four full calendar month period for the RC to review this information, and then a subsequent obligation for the RAS-entity to resolve any reliability issues identified by the RC prior to installing, functionally modifying, or retiring a particular RAS. Accordingly, these requirements do not contemplate immediate changes to existing physical assets, significant internal process transformations, or other issues that could potentially justify a three-year implementation period. Rather, they largely focus solely on the exchange and review of documentation, such as one-line drawings, for each RAS that is likely already be in the RAS-entity's possession today. RAS-entities and their associated RCs should therefore be able to begin the RAS review process with only minimal lead time following the adoption of PRC-12-2. Texas RE would further note that although RCs may need additional compliance resources to perform the RAS reviews contemplated under PRC-12-2, the existing language in PRC-12-2, R2 already provides RCs and RAS-entities with the flexibility to extend the review period if necessary based on a "mutually agreed upon schedule."

A similar rationale applies to the misoperation review and correction process in PRC-12-2, R5. As the SDT notes, "[t]he correct operation of a RAS is important for maintaining the reliability and integrity of the BES. *Any incorrect operation of a RAS indicates that the RAS effectiveness and/or coordination has been compromised.*" Texas RE agrees with this statement. In light of this fact, however, Texas RE believes that RAS-entities should begin RAS operational performance assessments following a RAS failure or misoperation immediately upon adoption of PRC-12-2 in order to avoid a significant reliability gap.

If the SDT elects to retain an implementation period of any length, Texas RE recommends that such implementation plan not apply to PRC-12-2, R4 and R8. These requirements already have significant time periods for RAS-entities to complete their compliance obligations embedded within them. For example, RAS-entities have six years under PRC-12-2, R8 to complete initial functional tests of their RAS (and 12 years for limited impact RAS if that definition is retained). Given that PRC-12-2, R4 and R8 already provide extended compliance horizons, Texas RE does not believe that additional time is necessary to implement these requirements. Instead, the 6-full-calendar month period in PRC-12-2, R4 and the six- and twelve-year periods in PRC-12-2, R8 should begin on the effective date of PRC-12-2 itself.

Additionally, the Implementation Plan contains the same "limited impact" language Texas RE has concerns about.

Texas RE requests the SDT provide justification for the testing timelines.

Likes 0	
Dislikes 0	

Response

Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	Yes
Document Name	

Comment

There was no general comment section provided this round, so TVA is providing the following comments to support our negative votes on the ballot:

TVA continues to believe that the responsibility for reviewing and approving new or functionally modified RAS schemes belongs with the Planning Coordinator and not the Reliability Coordinator. Oversight of the planning of the Bulk Electric System or the entities responsible for Bulk Electric System planning belongs with the Planning Coordinator.   From TVA's perspective, the proposed standard, as written, is in direct conflict with the Functional Model, and requires a compelling reason to justify the deviation. The facts that there are fewer Reliability Coordinators (as opposed to Planning Coordinators) and that the Reliability Coordinators have the "widest-area view" do not support a significant deviation from the Functional Model. Moreover, such analysis would beyond the normal Reliability Coordinator functions, the Reliability Coordinators would not have the expertise to conduct RAS analysis in the planning horizon. Simply put, Reliability Coordinators do not have trained personnel or the appropriate tools to complete a comprehensive assessment. Planning Coordinators have oversight over all other aspects of planning of the Bulk Electric System, and there is no reason to treat Remedial Action Schemes differently.

Likes 0	
Dislikes 0	

Response

Ben Engelby - ACES Power Marketing - 6, Group Name ACES Standards Collaborators - PRC-012-2 Project

Answer	Yes
Document Name	

Comment

We agree with the SDT that the implementation plan is appropriate.

Likes 0	
Dislikes 0	

Response

William Temple - William Temple

Answer	Yes
Document Name	

Comment

PJM supports the comments submitted by the ISO/RTO Council.

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC-ISONE

Answer	Yes
Document Name	

Comment	
The rationale for R2 states that RC review “minimizes the possibility of a conflict of interest that could exist because of business relationships among ….”. This explanatory purpose for R2 is not needed and in fact could prove untrue as not all RCs are independent from TOs, GOs, etc. The R3 rationale inserts the idea of “lack of dependability”. This can be understood differently by different parties. For a hardware supplier, it can mean the equipment or technology is unreliable. And if taken to an extreme, this seems to open the path to requiring the RC to decide which generators should run based on the individual generators’ forced outage rate (dependability rate?). We suggest this phrase be stricken from the R3 explanatory. For R4 the limited impact designation explanation, please clarify whether the reference to regions is meant to be an example of how the SDT came to its decision for R4 or whether it is a reference of the authority of what regions can do. We believe it is the former and the language should be improved. The concept of 4.1.2 to “avoid adverse interactions” would seem to need some criteria for evaluating what “avoid” means. Rather than state “avoid”, we suggest this requirement to be rewritten to state: “The RAS does not adversely impact the performance of other RAS, and protection and control systems.” 4.1.4.4. BES voltages shall be within post Contingency voltage limit is set by the Transmission Planner and the Planning Coordinator. Some Planners don’t use voltage deviation criteria. This should it not be rewritten to state “BES voltages shall be within the Planning Coordinator’s voltage criteria under pre and post contingency conditions”.	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Larry Heckert	
Answer	Yes
Document Name	
Comment	
Alliant Energy supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No HQ and Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Oshani Pathirane - Oshani Pathirane	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Teresa Czyz - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Greg Davis	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michael DeLoach - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael DeLoach - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - City and County of San Francisco - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Additional Comments:

PSEG

Requirement 1 – There are no clear lines of responsibility for jointly owned RASs.

The concept of a RAS-entity causes RAS-entity causes confusion for entities that have joint ownership of a RAS. While the SDT recognizes this issue by stating: " Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate and submit a single, coordinated Attachment 1to the reviewing RC". While PSEG agrees with the intent of this statement, it is included in the "Rationale" section of the draft standard and therefore that language will not be incorporated into the final standard. Furthermore, PSEG believes that PSEG that the language of R1 would still require each RAS entity to submit all information in Attachment 1to the Reliability Coordinator, which is inconsistent with the Paragraph 81 effort and the Reliability Assurance Initiative. PSEG believes such intent could be incorporated in to R1 as follows:

R1. Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, ~~each~~ the RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. If there are multiple RAS-entities, the entities may delegate a single mutually agreeable RAS-entity to submit Attachment 1 on their behalf.

PSEG wishes to note that such language would not be useful in situations where the one or more of the RAS-entities that jointly own a RAS do not want to cooperate or cannot agree upon a single lead entity. Additionally, PSEG believes that a single entity (either the Reliability Coordinator or the Planning Coordinator) should be responsible for coordinating the RAS entities.

Attachment 1 – Attachment 1 should have defined roles for the Planning Coordinator (PC) or Transmission Planner (TP).

Since the requirement for new and revised remedial action schemes are likely to be initiated by the results of Transmission system planning performance assessments done by the TP or PC in compliance with TPL-001-4, one of those entities would be best suited to perform many of the activities listed under section II of Attachment 1.

Furthermore, the technical studies that are required by Attachment 1 should not be performed individually by each RAS-entity because they do not have the skills or tools available to perform such analyses. For example, if an independent generator is asked by its RC to implement a run-back scheme to resolve a stability issue, it is unlikely that that entity would have to tools available to provide the information required under Attachment 1, item II.6.

Rather, PSEG recommends that the RAS-entities' PC or (TP) conduct the assessment of the System performance of a proposed new, modified, or retired RAS. Under this construct a RAS-entity implementing a new, modified, or retired RAS would submit an application under R1 containing general information as well as details concerning the proposed components and logic of the RAS to its TP or PC and to other RAS-entities that would participate in the RAS The PC or TP in turn would conduct the assessment of the proposed RAS to determine if the proposed RAS resolves the System performance issues, and forward that information to the RC for consideration under Requirement 2.

Seattle City Light

Project 2010-05.3 PRC-012-2 RAS Seattle City Light Comments Additional Ballot and Non-Binding Poll March 16, 2016

SCL COMMENTS
Clarification of Roles and Responsibilities for RAS Equipment Ownership by Multiple Entities:
4.1.3 RAS-entity
The RAS-entity is any Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If all of the RAS (RAS components) have a single owner, then that RAS entity has sole responsibility for all the activities assigned within the standard to the RAS-entity. If the RAS (RAS components) have more than one owner, then each separate RAS component owner is a RAS-entity and is obligated to participate in various activities identified by the Requirements.

The standard does not stipulate particular compliance methods. RAS-entities have the option of collaborating to fulfill their responsibilities for each applicable requirement. Such collaboration and coordination may promote efficiency in achieving the reliability objectives of the requirements; however, the individual RAS-entity must be able to demonstrate its participation for compliance. As an example, the individual RAS-entities could collaborate to produce and submit a single, coordinated Attachment 1 to the reviewing RC pursuant to Requirement R1 to initiate the RAS review process.

Per 4.1.3 RAS-entity discussion, City Light does not agree with the current definition from within the standard or the way responsibility is assigned. Compliance responsibility is being assigned to entities that cannot, by themselves, perform required actions to achieve compliance. Instead, entities that participate in a RAS scheme must rely on the original or current designer and owner of the scheme to perform work and perform coordination efforts. Without assigning primary and secondary (minor) RAS-entity responsibilities, issues could arise that are beyond the control of obligated entities. For an entity that only has end of the line equipment involved in the scheme, such as breaker trip coils, too much obligation falls on this entity that has a minor role. A large number of entities will fall into the category of owning a very small supporting portion of a RAS scheme and who do not have the means (information they do not control or determine) to perform the required reporting. Differentiation should be made between the primary RAS-entity (owner of a RAS scheme, primary) and owners of pieces of equipment who play a minor role for the primary RAS scheme. The standard should be rewritten to differentiate between primary and secondary (minor) to clarify roles and responsibilities.

As was mentioned in previous draft comments by others, this standard works great when there is one entity that owns the entire scheme. R3, R5, R6, R7, and R8 should be revised to designate overall responsibility to an owner of the scheme, with all secondary (minor participants) involved in the scheme being required to support the owner of the scheme in their development and reporting obligations. The primary RAS-entity that designs, owns and controls the RAS should be the one responsible for coordinating and meeting these requirements from the standard.

Other possible implications:
City Light additionally suggests that the term RAS-entity only apply to this standard and not be placed in the Glossary of Terms. If City Light is labeled as a RAS-entity under this current drafted definition, we would be defined as owning some or all of a RAS. There are no approved definitions for a RAS Owner. Project 2010-05.3 PRC-012-2 RAS Seattle City Light Comments Additional Ballot and Non-Binding Poll March 16, 2016

Other standards that assign RAS responsibilities do so under the applicability verbiage of "XXXX that owns an SPS". City Light feels this would impose undue confusion and compliance responsibility on entities that are minimally involved in a RAS. Therefore, RAS Entity should be only applicable to this standard.

We suggest adding the below defined term and language which would help serve three purposes. First to clarify who has responsibility for certain aspects of this standard. Secondly, to help clarify which entity has responsibility under current and future enforced RAS related standards such as PRC-017-1. Lastly, the proposed term would align with current WECC assignments of RAS responsibility.

> RAS-owner—the Transmission Owner, Generator Owner, or Distribution Provider that is the majority owner and operator of a RAS, this is normally identified using the following prioritization;
>
> The RAS-owner is the Transmission Owner of the scheme. Where there is not a Transmission Owner that owns a portion of the RAS, the Generator Owner becomes the RAS-owner. Where there is not a Transmission Owner or a Generator Owner that owns a portion of the RAS, the Distribution Provider becomes the RAS-owner.

In conclusion, revising the standard to clarify roles and responsibilities between the primary and secondary (participants) is crucial to the successful implementation of this standard when RAS components are owned by multiple entities.

Thanks you for your time and efforts in developing a successful standard

Consideration of Comments

Project Name: 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS) | PRC-012-2

Comment Period Start Date: 2/3/2016

Comment Period End Date: 3/18/2016

Associated Ballots: 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes PRC-012-2 AB 3 ST, 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes PRC-012-2 Non-binding Poll AB 3 NB

There were 43 responses, including comments from approximately 131 different people from approximately 84 different companies representing 8 of the 10 Industry Segments as shown on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Howard Gugel (via email) or at (404) 446-9693.

The drafting team made grammatical edits and footer updates to all documents and provided additional information in the Rationale boxes and Supplemental Material section of the draft standard based on stakeholder comments.

Questions

1. **PRC-012-2: Requirements R4 and R6, Attachments 1 and 2, and the Supplemental Material section of the standard were modified for clarity and completeness. Do you agree with the proposed changes? If no, please provide the basis for your disagreement and an alternate proposal.**

2. **Implementation Plan for PRC-012-2: The drafting team revised the Implementation Plan to provide for the initial consideration of limited impact RAS, and to clarify that the initial obligation under Requirement R9 for a Reliability Coordinator that does not have a RAS database is to establish a RAS database by the effective date of PRC-012-2. Do you agree with the revised Implementation Plan? If no, please provide the basis for your disagreement and an alternate proposal.**

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Ben Engelby	6		ACES Standards Collaborators - PRC-012-2 Project	Ellen Watkins	Sunflower Electric Power Corporation	1	SPP RE
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Mark Ringhausen	Old Dominion Electric Cooperative	3,4	RF
					Caitlin Schiebel	Buckeye Power, Inc.	4	RF
					John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc. and Southwest Transmission Cooperative, Inc.	1,4,5	WECC

					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Chip Koloini	Golden Spread Electric Cooperative	5	SPP RE
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	SPP RE	SRC-ISONE	Charles Yeung	SPP	2	SPP RE
					Ben Li	IESO	2	NPCC
					Ali Miremadi	CAISO	2	WECC
					Greg Campoli	NYISO	2	NPCC
					Liz Axson	ERCOT	2	Texas RE
					Lori Spence	MISO	2	MRO
					Mark Holman	PJM	2	RF
Public Service Enterprise Group	Christy Koncz	1,3,5,6	NPCC,RF	PSEG	Tim Kucey	PSEG - PSEG Fossil LLC	5	RF
					Karla Jara	PSEG - Energy Resources and Trade LLC	6	RF
					Joseph Smith	PSEG - Public Service	1	RF

						Electric and Gas Co.		
					Jeffrey Mueller	PSEG - Public Service Electric and Gas Co	3	RF
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
SERC Reliability Corporation	David Greene	10	SERC	SERC DRS	Mei Li	Entergy	1	SERC
					Zakia El Omari	GTC	1	SERC
					Wade Richards	SCPSA	1	SERC
					Bob Jones	Southern Company Services	1	SERC
					John O'Connor	DEP	1	SERC
					John Sullivan	Ameren	1	SERC
					Tom Cain	TVA	1	SERC
					Venkat Kolluri	Entergy	1	SERC
MRO	Emily Rousseau	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Joe Depoorter	Madison Gas & Electric	3,4,5,6	MRO
					Chuck Lawrence	American Transmission Company	1	MRO

					Chuck Wicklund	Otter Tail Power Company	1,3,5	MRO
					Dave Rudolph	Basin Electric Power Cooperative	1,3,5,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Jodi Jenson	Western Area Power Administration	1,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Mahmood Safi	Omaha Public Utility District	1,3,5,6	MRO
					Shannon Weaver	Midwest ISO Inc.	2	MRO
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Brad Perrett	Minnesota Power	1,5	MRO
					Scott Nickels	Rochester Public Utilities	4	MRO
					Terry Harbour	MidAmerican Energy Company	1,3,5,6	MRO

					Tom Breene	Wisconsin Public Service Corporation	3,4,5,6	MRO
					Tony Eddleman	Nebraska Public Power District	1,3,5	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Dana Wheelock	Seattle City Light	3	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,3,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
Southern Company - Southern	Pamela Hunter	1,3,5,6	SERC	Southern Company	Robert A. Schaffeld	Southern Company Services, Inc.	1	SERC

Company Services, Inc.					R. Scott Moore	Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					John J. Ciza	Southern Company Generation and Energy Marketing	6	SERC
Dominion - Dominion Resources, Inc.	Randi Heise	5		Dominion - RCS	Larry Nash	Dominion Virginia Power	1	SERC
					Louis Slade	Dominion Resources, Inc.	6	SERC
					Connie Lowe	Dominion Resources, Inc.	3	RF
					Randi Heise	Dominion Resources, Inc.	5	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC No HQ and Dominion	Paul Malozewski	Hydro One	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Brian Shanahan	National Grid	1	NPCC

					Rob Vance	New Brunswick Power	1	NPCC
					Mark J. Kenny	Eversource Energy	1	NPCC
					Gregory A. Campoli	NY-ISO	2	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					David Ramkalawan	Ontario Power Generation	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Michael Jones	National Grid	3	NPCC

					Michael Forte	Con Edison	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	UI	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Helen Lainis	IESO	2	NPCC
					Michele Tondalo	UI	1	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Silvia Parada Mitchell	NextEra Energy, LLC	4	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Jason Smith	Southwest Power Pool Inc.	2	SPP RE
					Patrick McPhail	Grand River Dam Authority	1	SPP RE
					Robert Hirchak	Cleco	1,3,5,6	SPP RE
					Jamison Cawley	Nebraska Power Public District	1,3,5	MRO

					Greg Hill	Nebraska Power Public District	1,3,5	MRO

1. PRC-012-2: Requirements R4 and R6, Attachments 1 and 2, and the Supplemental Material section of the standard were modified for clarity and completeness. Do you agree with the proposed changes? If no, please provide the basis for your disagreement and an alternate proposal.

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RF	
Answer	No
Comment	

We object to Generator Owners having a primary role in this standard. The nature of a RAS is not to protect individual generators, for these must have adequate protection for faults or abnormal operating situations. The RAS is typically designed to maintain the reliability of a significant area of the overall power system. As such, the Transmission Owner is the best entity to ensure that RAS are employed correctly. Unlike the GO, the TO has the "wide-area" scope of monitoring and system responsibility.

The draft standard is deficient due to the patchwork nature of responsibility for a RAS, especially when there are multiple Owners of portions of the RAS. There needs to be a single RAS Owner that has overall responsibility for ensuring the requirements of PRC-012-2 are met. This RAS Owner should be a Transmission Owner, not a Generator Owner. The TO (RAS Owner) should take the lead in developing the data needed for requirements R1 and R3, with the other RAS entities being required to provide data and equipment modifications as needed. Requirements R5 through R8 should apply to the RAS-Owner, not the RAS entities. The RAS Owner should be the point of contact with the Planning Coordinator/Reliability Coordinator, with the RAS entities having responsibility to collaborate with the RAS Owner as needed.

Likes 1	U.S. Bureau of Reclamation, 5, Doot Erika
Dislikes 0	
Response	

Thank you for your comments.

The drafting team is charged with assigning the requirements of PRC-012-2 to the specific users, owners, and operators of the Bulk-Power System while incorporating the reliability objectives of all the RAS-related standards. The term RAS-entity is defined in the Applicability as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. For purposes of PRC-012-2, a

Generator Owner (RAS-entity) that owns RAS components is responsible to participate in the various activities identified by the requirements to the extent of its ownership. RAS-entities have the option of collaborating to fulfill their responsibilities for each applicable requirement; however, the individual RAS-entity must be able to demonstrate its participation for compliance.	
Daniel Mason - City and County of San Francisco - 5	
Answer	No
Comment	
The Standards identifies a RAS-entity as "the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS". In some cases this "part" could be as limited as a sensing device providing input to another entity's RAS logic and interupting devices. For those RAS-entities that find themselves in that situation, providing the information identified in Attachments 1 and 2 is not appropriate. The Standard should clear up reporting responsibilities for such minor RAS-entities, perhaps by employ the concept of a "RAS Reporting Agent" for each RAS.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. For purposes of PRC-012-2, the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS is a RAS-entity as defined in the Applicability. The RAS-entity is responsible to participate in the various activities identified by the requirements to the extent of its ownership. RAS-entities have the option of collaborating to fulfill their responsibilities for each applicable requirement; however, the individual RAS-entity must be able to demonstrate its participation for compliance.	
Gul Khan on Behalf of Rod Kinard, Oncor Electric Delivery - 1	
Answer	No
Comment	
Oncor does not currently provide the documents mentioned on page 21 of the PRC-012-2 draft 3 standard bullet # 1. We can provide a simple map of where a RAS will be located but if we are being requested to provide relay functional drawings or detailed 3 line	

schematics we won't have those drawings developed until the RAS is approved. Additionally even if we have the documents and do send it to ERCOT, we have a confidentiality concern as these files will get posted in a public information database. We have touched base with our RC, ERCOT, and they agree that the process we are doing today is satisfactory and is working. Hence we do not see a need to provide the documentation in attachment 1. The additional information should be optional.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. To facilitate a review that promotes reliability, the RAS-entity must provide the RC sufficient details (identified in Attachment 1) of the RAS design, function, and operation. The information described in Appendix 1 (while not identical) is similar to the information required by most Regional Entities as part of existing RAS review and approval processes. As stated in Attachment 1, if an item on this list does not apply to a specific RAS, a response of "Not Applicable" for that item is appropriate. The level of detailed information required is ultimately at the discretion of the RC. The RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS. If Oncor and ERCOT (the reviewing RC) agree that the documentation provided for RAS review is Critical Infrastructure Information (CII), all entities involved should handle the information in accordance with all applicable CII guidelines. PRC-012-2 does not require that the RAS documentation or review be public.	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Comment	
SRP appreciates the efforts of the SDT and recommends the removal of the language in the attachments that refers to a "checklist". Initial drafts of the attachments were checklists. What is presented cannot be described as a "checklist". SRP believes this language will create confusion. SRP further recommends removing the definition for "limited impact" from the footer of the attachment. If this is to be a definition, it should be defined in the NERC Glossary of Terms.	

SRP recommends the removal of the definition for "Functionally Modified" from the footer of the documents. Capitalized terms are to be part of the NERC Glossary of Terms and should not be located outside of that body of work.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The drafting team regards Attachments 1 and 2 as checklists and maintains they should be used as such by the RAS-entity (Attachment 1) and Reliability Coordinator (Attachment 2). The Reliability Coordinator has responsibility for the reliability of BES operations within its Reliability Coordinator Area and consequently has the responsibility to review and approve each RAS before it is implemented in its RC Area. Furthermore, the RC has the discretion to designate a RAS as limited impact, if applicable, on a case-by-case basis. The drafting team maintains that the general description and explanatory language regarding the limited impact designation does not rise to the level of a definition that should be included in the Glossary of Terms Used in NERC Reliability Standards; instead, it provides high-level guidance for the RC to consider during the RAS review. The term "functionally modified," which is incorporated into the standard by reference to Attachment 1, is only intended to provide guidance to responsible entities for complying with PRC-012-2. The footnote contains examples of what would be considered "functionally modified." The drafting team maintains that this guidance does not rise to the level of a definition that should be included in the Glossary of Terms Used in NERC Reliability Standards, and the footnote is a workable location for this information. The capitalization of the word "modified" in footnotes 2, 4, and 8 was an error and was corrected. Thank you for pointing this out.	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	No
Comment	
AZPS appreciates the efforts of the Standard Drafting Team (SDT) to date and makes the following comments:	

The materials state that a limited impact RAS is "determined by the RC". AZPS suggests modifying the language to "…limited impact RAS as determined by the RC based on predefined regionally appropriate criteria." An RC's determination of whether a RAS is limited impact should include an evaluation of the potential impacts of the RAS and should reference pre-defined regionally appropriate criteria defined through a regionally accepted process (e.g. via the RASRC in WECC). The Technical Justification section directed to Limited Impact states, "The reviewing RC is the sole arbiter for determining whether a RAS qualifies for the limited impact designation." While not in direct conflict, AZPS believes that some entities may misinterpret the modified language as limiting the "The RC from requesting assistance in RAS reviews from other parties such as the PC(s) or regional technical groups (e.g., Regional Entities)" as provided for earlier in the document. AZPS requests that the "sole arbiter" sentence be clarified to address this concern. R4.1.3 is currently amended to state "for limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations." The word "contribute" should be removed because it reduces clarity to the standard. The term "contribute" is too broad and creates challenges to precisely evaluate. AZPS appreciates the DT addressing the concern of cases where a RAS crosses one or more RC Area boundaries, each affected RC is responsible for conducting either individual reviews or participating in a coordinated review by adding language in the appropriate rational and Supplemental Material sections. AZPS requests the SDT consider if this information would be more impactful as a footnote to the requirements themselves.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. The drafting team maintains that the RC is the functional entity best suited to perform the RAS reviews because it has the widest area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. This Wide Area purview facilitates the evaluation of interactions among separate RAS as well as interactions among the RAS and other protection and control systems. The RC has the most comprehensive operational knowledge of the BES in its RC Area. The drafting team declines to make the suggested change of adding "based on predefined regionally appropriate criteria" as it is not necessary.

The RC may request and consider input from various parties on any decision. The fact that the RC is responsible for making the final decision; i.e., is the "sole arbiter," does not preclude nor conflict with the RC's ability to request assistance or input; however, the drafting team made a clarifying revision to the wording in the Supplemental Material section for "limited impact".

Regarding the use of the term "contribute", the drafting team contends its inclusion is necessary. Usually, if not always, there is more than one cause or contributing factor for an event on the BES; whereby, the removal of any one of the individual contributing factors might have prevented or lessened the severity of the event. The drafting team declines to make the suggested change.

The drafting team sees no benefit in putting the existing language in a footnote and declines to make the suggested change.

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Comment	

Need to clarify roles and responsibilities for those RAS that are multi-jurisdictional. See Attached comments

Clarification of Roles and Responsibilities for RAS Equipment Ownership by Multiple Entities:

4.1.3 RAS-entity

The RAS-entity is any Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If all of the RAS (RAS components) have a single owner, then that RAS entity has sole responsibility for all the activities assigned within the standard to the RAS-entity. If the RAS (RAS components) have more than one owner, then each separate RAS component owner is a RAS-entity and is obligated to participate in various activities identified by the Requirements.

The standard does not stipulate particular compliance methods. RAS-entities have the option of collaborating to fulfill their responsibilities for each applicable requirement. Such collaboration and coordination may promote efficiency in achieving the reliability objectives of the requirements; however, the individual RAS-entity must be able to demonstrate its participation for compliance. As an example, the individual RAS-entities could collaborate to produce and submit a single, coordinated Attachment 1 to the reviewing RC pursuant to Requirement R1 to initiate the RAS review process.

Per 4.1.3 RAS-entity discussion, City Light does not agree with the current definition from within the standard or the way responsibility is assigned. Compliance responsibility is being assigned to entities that cannot, by themselves, perform required actions to achieve compliance. Instead, entities that participate in a RAS scheme must rely on the original or current designer and owner of the scheme to perform work and perform coordination efforts. Without assigning primary and secondary (minor) RAS-entity responsibilities, issues could arise that are beyond the control of obligated entities. For an entity that only has end of the line equipment involved in the scheme, such as breaker trip coils, too much obligation falls on this entity that has a minor role. A large number of entities will fall into the category of owning a very small supporting portion of a RAS scheme and who do not have the means (information they do not control or determine) to perform the required reporting. Differentiation should be made between the primary RAS-entity (owner of a RAS scheme, primary) and owners of pieces of equipment who play a minor role for the primary RAS scheme. The standard should be rewritten to differentiate between primary and secondary (minor) to clarify roles and responsibilities.

As was mentioned in previous draft comments by others, this standard works great when there is one entity that owns the entire scheme. R3, R5, R6, R7, and R8 should be revised to designate overall responsibility to an owner of the scheme, with all secondary (minor participants) involved in the scheme being required to support the owner of the scheme in their development and reporting obligations. The primary RAS-entity that designs, owns and controls the RAS should be the one responsible for coordinating and meeting these requirements from the standard.

Other possible implications:

City Light additionally suggests that the term RAS-entity only apply to this standard and not be placed in the Glossary of Terms. If City Light is labeled as a RAS-entity under this current drafted definition, we would be defined as owning some or all of a RAS. There are no approved definitions for a RAS Owner. Project 2010-05.3 PRC-012-2 RAS Seattle City Light Comments Additional Ballot and Non-Binding Poll March 16, 2016

Other standards that assign RAS responsibilities do so under the applicability verbiage of “XXXX that owns an SPS”. City Light feels this would impose undue confusion and compliance responsibility on entities that are minimally involved in a RAS. Therefore, RAS Entity should be only applicable to this standard.

We suggest adding the below defined term and language which would help serve three purposes. First to clarify who has responsibility for certain aspects of this standard. Secondly, to help clarify which entity has responsibility under current and future enforced RAS related standards such as PRC-017-1. Lastly, the proposed term would align with current WECC assignments of RAS responsibility.

RAS-owner—the Transmission Owner, Generator Owner, or Distribution Provider that is the majority owner and operator of a RAS, this is normally identified using the following prioritization;

The RAS-owner is the Transmission Owner of the scheme. Where there is not a Transmission Owner that owns a portion of the RAS, the Generator Owner becomes the RAS-owner. Where there is not a Transmission Owner or a Generator Owner that owns a portion of the RAS, the Distribution Provider becomes the RAS-owner.

In conclusion, revising the standard to clarify roles and responsibilities between the primary and secondary (participants) is crucial to the successful implementation of this standard when RAS components are owned by multiple entities.

Thanks you for your time and efforts in developing a successful standard

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

The term RAS-entity is applicable to PRC-012-2 only and will not be included in the Glossary of Terms Used in NERC Reliability Standards. For purposes of PRC-012-2, the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS is a RAS-entity as defined in the Applicability. The RAS-entity is responsible to participate in the various activities identified by the requirements to the extent of its ownership. RAS-entities have the option of collaborating to fulfill their responsibilities for each applicable requirement; however, the individual RAS-entity must be able to demonstrate its participation for compliance purposes.

The drafting team is charged with assigning the requirements of the new standard to the specific users, owners, and operators of the Bulk-Power System while incorporating the reliability objectives of all the RAS-related standards. In drafting this standard, the drafting team has worked diligently to minimize the changes that will be required from the existing processes. The drafting team recognizes that RAS with multiple owners inherently require coordination among all the participating RAS-entities from the first conceptual design through construction to operations, testing, maintenance and retirement.

For purposes of PRC-012-2, when a RAS has more than one owner, each RAS-entity is obligated to participate in the various activities identified by the requirements to the extent of its ownership. Collaboration, coordination, and communication between and among entities regarding RAS issues helps to ensure efforts are not duplicated and best serves reliability by promoting awareness. For purposes of creating efficiencies, the drafting team maintains registered entities that currently share ownership of a RAS (RAS-entities) are in some manner already communicating, sharing information, and coordinating RAS tasks such as operations analysis, Corrective Action Plan (CAP) development, and functional testing. The drafting team is confident that entities will continue to do this after this standard is effective and that entities will communicate with each other if there is any question or doubt of responsibility surrounding any requirement.

The drafting team contends that your proposed language would cause confusion and declines to make the suggested changes.

Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	
Answer	No
Comment	

Requirement 1 – There are no clear lines of responsibility for jointly owned RASs.

The concept of a RAS-entity causes RAS-entity causes confusion for entities that have joint ownership of a RAS. While the SDT recognizes this issue by stating: “ Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate and submit a single, coordinated Attachment 1to the reviewing RC”. While PSEG agrees with the intent of this statement, it is included in the “Rationale” section of the draft standard and therefore that language will not be incorporated into the final standard.   Furthermore, PSEG believes that PSEG that the language of R1 would still require each RAS entity to submit all information in Attachment 1to the Reliability Coordinator, which is inconsistent with the Paragraph 81 effort and the Reliability Assurance Initiative. PSEG believes such intent could be incorporated in to R1 as follows:

R1. Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, ~~each~~ the RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. <u>If there are multiple RAS-entities, the entities may delegate a single mutually agreeable RAS-entity to submit Attachment 1 on their behalf.</u>

PSEG wishes to note that such language would not be useful in situations where the one or more of the RAS-entities that jointly own a RAS do not want to cooperate or cannot agree upon a single lead entity. Additionally, PSEG believes that a single entity (either the Reliability Coordinator or the Planning Coordinator) should be responsible for coordinating the RAS entities.

Attachment 1 – Attachment 1 should have defined roles for the Planning Coordinator (PC) or Transmission Planner (TP).

Since the requirement for new and revised remedial action schemes are likely to be initiated by the results of Transmission system planning performance assessments done by the TP or PC in compliance with TPL-001-4, one of those entities would be best suited to perform many of the activities listed under section II of Attachment 1. Furthermore, the technical studies that are required by Attachment 1 should not be performed individually by each RAS-entity because they do not have the skills or tools available to perform such analyses. For example, if an independent generator is asked by its RC to implement a run-back scheme to resolve a stability issue, it is unlikely that that entity would have to tools available to provide the information required under Attachment 1, item II.6. Rather, PSEG recommends that the RAS-entities' PC or (TP) conduct the assessment of the System performance of a proposed new, modified, or retired RAS. Under this construct a RAS-entity implementing a new, modified, or retired RAS would submit an application under R1 containing general information as well as details concerning the proposed components and logic of the RAS to its TP or PC and to other RAS-entities that would participate in the RAS The PC or TP in turn would conduct the assessment of the proposed RAS to determine if the proposed RAS resolves the System performance issues, and forward that information to the RC for consideration under Requirement 2.	
Likes 2	Pragna Pulusani, N/A, Pulusani Pragna; PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
Dislikes 0	
Response	
Thank you for your comments. The drafting team declines to make the suggested change to Requirement R1. When this standard receives Board adoption, the Rationale boxes will be moved to the Supplemental Material section and will remain with the standard. PRC-012-2 is a results-based standard and not a prescriptive one; it is not the intent of the drafting team to specify how multiple RAS-entities must collaborate or coordinate. The drafting team is confident that entities will continue to communicate and work with each other as they do now. The drafting team maintains that the RAS-entity has the "flexibility" to request information or assistance from relevant entities (third parties) The drafting team maintains that the RC is the functional entity best suited to perform the RAS review because it has the widest area perspective of all functional entities and minimizes the possibility of a conflict of interest that could exist because of business	

relationships among the RAS-entity, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The drafting team agrees that the PC and/or TP would participate in providing Attachment 1 information. It is anticipated that the associated studies will likely be performed, in whole or in part, by the TP or PC; the RAS-entity is required only to provide the compiled Attachment 1 information.	
Greg Davis on Behalf of Jason Snodgrass, Georgia Transmission Corporation - 1	
Answer	No
Comment	

GTC Background:

There are multiple registered Planning Coordinators and jointly shared transmission system in GTC's Planning Area and it is important for each PC in the area to be notified prior to placing new or functionally modified RAS in-service or retiring an existing RAS. Equally as important, is for each PC in the area to be notified if CAP actions or timetables change when the CAP is completed pursuant to CAPs developed for R6. GTC's proposed considerations listed below are focused on mitigating operational and compliance risks associated with awareness and knowledge of new or functionally modified RAS where there are multiple registered PCs in a common RC Area.

R7.3:

Although R4.2 requires each impacted TP and PCs to be notified of results of a RAS evaluation, there is not a similar method for any impacted TP and/or PC to be notified in which a RAS was evaluated with identified deficiencies pursuant to CAPs developed for R6; nor when or if CAP is implemented in a timely manner or if timetables change. We propose including the phrase "and Planning Coordinators within the RAS-entity's area" in R7.3, which would read as follows: "Notify each reviewing Reliability Coordinator and Planning Coordinators within the RAS-entity's area, if CAP actions or timetables change and when the CAP is completed."

R9:

Even though it seems implied in R9 that the RAS database containing all pertinent data will be made available to impacted PCs and/or TPs in the RCs area, it is unclear. GTC proposes the following new requirement to compliment the obligations of the Planning Coordinator under requirement R4 if the aforementioned proposed changes to R7.3 are not adopted by the SDT.

R10 (proposed new requirement): Each Reliability Coordinator shall provide each Planning Coordinator in their Reliability Coordinator area a copy of the RAS database maintained in accordance with R9, at least once every twelve full calendar months.

R4.1.5:

Since a RAS is only required when the performance requirements of TPL-001-4 will not be met, is R4.1.5 essentially mandating redundancy for all RAS components? What does a single component failure constitute under Requirement R 4.1.5?

Clarification of limited impact RAS:

SERC DRS suggests a revision as to what constitutes a limited impact RAS. Currently, the language in the standard suggests that an RAS considered to be limited impact cannot:

"cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations"

We suggest revising the above language by inserting the term "widespread" before angular instability. Angular instability could be experienced by just one generating unit going out of sync. A single generating unit becoming unstable is not indicative of an unstable or unreliable BES, and we do not believe that this should remove an RAS from limited impact consideration.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

R7.3 comment: The notification of changes regarding CAP actions, timetables, or completion has a more immediate effect on the operation of the System rather than the planning of the System; therefore the standard requires the RC be notified of these changes. Because the RC is responsible for the reliability of the BES in its RC Area, the drafting team maintains that the RC has a vested interest in sharing pertinent data with functional entities that have reliability-related needs.

R9 comment: The drafting team contends that an additional requirement is not necessary, because as stated in the Rationale for Requirement R9, the RC can provide other functional entities (e.g. Transmission Operators and Planning Coordinators) high-level information/data on existing RAS that could potentially impact the operational and/or planning activities of that entity. Because the RC is responsible for the reliability of the BES in its RC Area, the drafting team maintains that the RC has a vested interest in sharing pertinent data with functional entities that have reliability-related needs.

R4.1.5 comment: The drafting team disagrees that a RAS is required when the performance requirements of TPL-001-4 will not be met; a RAS is one possible solution to resolve that issue. Requirement R4, Part 4.1.5 requires the PC to periodically perform an evaluation of each RAS within its planning area to determine whether, except for limited impact RAS, 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 is designed. Requirement R4, Part 4.1.5 does not mandate that all RAS have redundant components. For example, consider the instance where a RAS is installed to mitigate an extreme event in TPL-001-4. There are no System performance requirements for extreme events; therefore, the RAS does not need redundancy to meet the same performance requirements as those required for the events and conditions for which the RAS was designed. A single component failure would be the failure of any one of the components of a RAS. A list of individual components is not practical given the variety that could be applied in RAS design and implementation. See Item 4a in the Implementation Section of Attachment 1 in the Supplemental Material section for typical RAS components for which a failure may be considered.

The drafting team avoids the use of adjectives such as “widespread” because of the ambiguity those terms introduce. The drafting team maintains that the “BES” qualifier in the statement regarding the limited impact designation modifies all of the conditions that follow; i.e., Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, and unacceptably damped oscillations. As you suggest, the instability of a single generating unit or small generating plant would not be indicative of an unstable or unreliable BES; however, the RC is the final arbiter for determining whether the RAS qualifies for limited impact status based upon review of the Attachment 1 information.

Ben Engelby - ACES Power Marketing - 6, Group Name ACES Standards Collaborators - PRC-012-2 Project

Answer	No

Comment

1. RAS-entity causes confusion for entities that have joint ownership of a RAS. We recommend the SDT develop guidance to support the requirements and expectations for joint owners to meet compliance. For RAS with multiple RAS-entities, who is responsible for overall coordination to assure complete and consistent data submittals in order to meet compliance with this standard?
2. For R2, we remain concerned by the term “mutually agreeable” and how it will be applied.

3. Why did the SDT give the RC the authority to determine “limited impact” RAS without providing objective criteria or guidelines? The SDT cited Local Area Protection Scheme (LAPS) in WECC and the Type 3 designation in NPCC. What about the other regions? There should be a specific set of parameters for the RC to make a decision. We suggest developing continent-wide criteria for determining limited impact RAS and not referring to only two regional approaches.
4. Why does the SDT include “limited impact” RAS as being applicable to the standard? If it has a limited impact, then it should not apply at all. This proposal by the SDT is contrary to the past two years of NERC’s RAI and RBR initiatives focusing on HIGH RISK activities. By definition, “limited impact” should not matter for BES reliability. The limited impact designation creates unnecessary compliance burdens without a clear benefit to increased reliability of the BES.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

PRC-012-2 is a results-based standard and not a prescriptive one; it is not the intent of the drafting team to specify how multiple RAS-entities must collaborate or coordinate. The drafting team is confident that entities will continue to communicate and work with each other as they do now. For purposes of PRC-012-2, the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS is a RAS-entity as defined in the Applicability. The RAS-entity is responsible to participate in the various activities identified by the requirements to the extent of its ownership. RAS-entities have the option of collaborating to fulfill their responsibilities for each applicable requirement; however, the individual RAS-entity must be able to demonstrate its participation for compliance purposes.

The time frame of four full calendar months for RAS reviews is consistent with current utility and regional practices. The drafting team wrote the requirement to permit either shorter or longer time intervals for a RAS review provided all the affected parties agreed to the alternate time.

The drafting team maintains that the RC is the functional entity best suited to perform the RAS reviews because it has the widest area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. This Wide Area purview facilitates the evaluation of interactions among separate RAS as well as interactions among the RAS and other protection and control systems. Because the RC has the most comprehensive operational knowledge of the BES in its RC Area, the drafting team contends the

RC, armed with the studies and other information provided with the Attachment 1 submittal, is capable of making a well-reasoned determination of a RAS, including whether it qualifies for the limited impact designation.

WECC and NPCC were cited because those are the only two Regions that classified RAS based upon certain criteria. The SPCS-SAMS team also recognized these Regional classifications and made similar albeit different recommendations. The drafting team considered the attributes of each of these Regional classifications in creating the guidance for limited impact designation. The limited impact designation is applicable on a continent-wide basis via NERC Reliability Standard PRC-012-2.

While a limited impact RAS presents a lower risk to BES reliability, the limited impact designation should not be construed as zero impact or risk. PRC-012-2 is applicable to all RAS under the new FERC approved RAS definition. In addition, System changes could occur to cause a RAS to no longer qualify as limited impact so the designation is not permanent. Please reference Requirement R4, Part 4.1.3. The drafting team disagrees with your premise regarding the compliance burden. The RAS-entity is not obligated to request a RAS be considered for limited impact designation; i.e., provide the necessary analyses and/or studies to demonstrate that the RAS should be considered limited impact.

Teresa Czyz - Oglethorpe Power Corporation - 5	
Answer	No
Comment	

OPC agrees with GTC's comments:

There are multiple registered Planning Coordinators and jointly shared transmission system in GTC’s Planning Area and it is important for each PC in the area to be notified prior to placing new or functionally modified RAS in-service or retiring an existing RAS. Equally as important, is for each PC in the area to be notified if CAP actions or timetables change when the CAP is completed pursuant to CAPs developed for R6. GTC’s proposed considerations listed below are focused on mitigating operational and compliance risks associated with awareness and knowledge of new or functionally modified RAS where there are multiple registered PCs in a common RC Area.

R7.3:

Although R4.2 requires each impacted TP and PCs to be notified of results of a RAS evaluation, there is not a similar method for any impacted TP and/or PC to be notified in which a RAS was evaluated with identified deficiencies pursuant to CAPs developed for R6; nor when or if CAP is implemented in a timely manner or if timetables change. We propose including the phrase “and Planning Coordinators within the RAS-entity's area" in R7.3, which would read as follows: "Notify each reviewing Reliability Coordinator and Planning Coordinators within the RAS-entity's area, if CAP actions or timetables change and when the CAP is completed."

R9:

Even though it seems implied in R9 that the RAS database containing all pertinent data will be made available to impacted PCs and/or TPs in the RCs area, it is unclear. GTC proposes the following new requirement to compliment the obligations of the Planning Coordinator under requirement R4 if the aforementioned proposed changes to R7.3 are not adopted by the SDT.

R10 (proposed new requirement): Each Reliability Coordinator shall provide each Planning Coordinator in their Reliability Coordinator area a copy of the RAS database maintained in accordance with R9, at least once every twelve full calendar months.

R4.1.5:

Since a RAS is only required when the performance requirements of TPL-001-4 will not be met, is R4.1.5 essentially mandating redundancy for all RAS components? What does a single component failure constitute under Requirement R 4.1.5?

Clarification of limited impact RAS:

SERC DRS suggests a revision as to what constitutes a limited impact RAS. Currently, the language in the standard suggests that an RAS considered to be limited impact cannot:

"cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations"

We suggest revising the above language by inserting the term "widespread" before angular instability. Angular instability could be experienced by just one generating unit going out of sync. A single generating unit becoming unstable is not indicative of an unstable or unreliable BES, and we do not believe that this should remove an RAS from limited impact consideration.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

Please see the drafting team's responses to the referenced comments.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Comment	
Requirement 4 of the standard puts the burden of performing the studies on the PC. PNM as a registered PA/PC doesn't contest the assignment of the requirement to the PC; however, the standard doesn't guarantee that the PC will be provided with the data required to perform the assessment. PNM proposes adding a requirement for the RAS entity to provide data required to assess the RAS within 30 calendar days of receiving approval from the RC so that the PC can obtain the information required to adequately assess each scheme every five full calendar years. The information provided to the RC in R5.2, R6, R7.3 would impact the R4 assessment; therefore, the PC should also be receiving this information.	
Likes 0	
Dislikes 0	
Response:	
Thank you for your comments. The drafting team maintains that the RAS-entity has a vested interest in getting the Requirement R4 review completed on time and will therefore provide the data to the PC without being mandated by a requirement. The notification of changes regarding CAP actions, timetables, or completion has a more immediate effect on the operations of the System versus the planning of the System; therefore the standard requires the RC be notified of these changes. Because the RC is responsible for the reliability of the BES in its RC Area, the drafting team maintains that the RC has a vested interest in sharing pertinent data with functional entities that have reliability-related needs. The drafting team declines to make the suggested change.	
Jared Shakespeare - Peak Reliability - 1	
Answer	No
Comment	

What is the required evaluation for the PC in R4? For the RC it is clear to follow Attachment 2 for the evaluation but the PC in R4 does not have any explicit evaluation requirement. We recommend adding language that describes the PC adhering at a minimum, but not limited to, Attachment 2 for their 5 year evaluation. Both R4.1.4 and Attachment 1, section III, item 4 use the same language, "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 is designed." Though similar language is used in the currently effective set of reliability standards, it is confusing and unclear. We recommend providing examples in an application guideline as part of the standard itself that might help the reader understand the meaning of and intent behind this language.	
Likes 0	
Dislikes 0	
Response:	
Thank you for your comments. The drafting team maintains that Requirement R4 provides the desired reliability objectives without being prescriptive or explicit regarding the methodologies used to attain them. The review of Requirement R2 focuses on the design and implementation aspects of the RAS whereas the periodic evaluations of Requirement R4 are focused on the planning analyses and System impacts related to the RAS. While aspects of Attachment 2 could be used by the PC during its evaluations, the drafting team disagrees with the suggestion to require the use of Attachment 2 in Requirement R4. The drafting team provided examples in the Supplemental Material section for Requirement R4 as you requested.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Comment	

Duke Energy suggests a revision as to what constitutes a limited impact RAS. Currently, the language in the standard suggests that an RAS considered to be limited impact cannot: *"cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations"* We suggest revising the above language by inserting the term "widespread" before angular instability. Angular instability could be experienced by just one generating unit going out of sync. A single generating unit becoming unstable is not indicative of an unstable or unreliable BES, and we do not believe that this should remove an RAS from limited impact consideration. Duke Energy also reiterates its concern regarding the compliance implications of potentially requiring the RC to be responsible for the technical correctness of an RAS-entity's information it provides in Attachment 1. An RC should only be held responsible for the "wide area purview" or conceptual appropriateness of a new or functionally modified RAS, and not be held responsible for potential mistakes made by the RAS-entity during the process.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. The drafting team avoids the use of adjectives such as "widespread" because of the ambiguity those terms introduce. The drafting team maintains that the "BES" qualifier in the statement regarding the limited impact designation modifies all of the conditions that follow; i.e., Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, and unacceptably damped oscillations. As you suggest, the instability of a single generating unit or small generating plant would not be indicative of an unstable or unreliable BES; however, the RC is the final arbiter for determining whether the RAS qualifies for limited impact status based upon review of the Attachment 1 information. The RC cannot, under Requirement R2, be held responsible for the technical correctness of a RAS-entity's information but only that a review covering the items in Attachment 2 has been accomplished. It is possible and certainly desirable that a RC might uncover errors in a RAS-entity's information during a review exercised with appropriate diligence, but not a requirement.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Comment	

Would suggest the drafting team develop a Standards Authorization Request (SAR) for the term 'limited impact' and propose the term be added to the NERC Glossary and Rules of Procedure (RoP) to promote consistency and clarity. During our current evaluation of this draft of the Standard and RSAW, we are concerned that the Rationale box information (page 5 of the Standard-next to the sentence) is not consistent with the Requirement R4 sub-part 4.1.3. Another concern is that we feel the sub-part states the proposed definition of 'limited impact' twice. At the first use, the term 'limited impact' is stated with a footnote-4 "A RAS designated as 'limited impact' cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations" then this same information is stated again after the term. We suggest the drafting team use some different language besides "verify the limited impact designation remains applicable" which was stated in the Rationale box in order to make it clear just what the SDT intends the reviewer to do.

Additionally, we interpret that in the RSAW (note to Auditor-Section Requirement R4) there is an attempt to define the term 'Inadvertent operation'. If this is the case, we would suggest the review panel/drafting team should develop a SAR for that particular term and propose that it be included in the NERC Glossary of Terms and Rules of Procedure (RoP) as well as including that term in the Standard again to promote consistency and clarity.

For Requirement R6, we have a concern that the translation of the Rationale and Technical data (in the Standard) and the Note to Auditor information (in the RSAW) may become lost. As we have evaluated both documents, it seems more evident that the Rationale and Technical information needs to be included in the RSAW. This information has been included in the Standard to help provide a solid foundation to each Requirement to help support the auditing process. However, this information isn't included in the RSAW which leads to potential inconsistency in the auditing process. We feel that both documents need to contain the same information in order to be properly aligned.

Finally, our last concern would be having all maintenance requirements implemented into one document. Currently, we agree that Requirement R8 pertains to performing maintenance associated with Functional Testing as well as verifying proper operation of non-protection system components (system maintenance). However, we suggest moving Requirement R8 into the PRC-005 Standard for consistency in reference to maintenance requirements.

Likes 0	

Dislikes 0	
Response	
Thank you for your comments. The drafting team maintains that the general description and explanatory language regarding the limited impact designation does not rise to the level of a definition that should be included in the Glossary of Terms Used in NERC Reliability Standards; instead, it provides high-level guidance for the RC to consider during the RAS review. The drafting team notes that the commenter has the correct understanding of Requirement R4, Part 4.1.3 that the Planning Coordinator must verify the limited impact designation remains applicable for each RAS previously designated as such. The drafting team prefers to keep the existing language and therefore declines to make the suggested change. The RSAW is a document used as a guide for auditors to assess compliance with the standard and includes the statement: "Inadvertent operation refers to an operation of the RAS when the RAS is not intended to operate." The drafting team maintains the dictionary definition of the term "inadvertent," which is "not intended or planned" is clear and unambiguous. Information in the Rationale boxes and Supplemental Material section of the draft standard is important to explain the foundation for each requirement of the standard; whether or not that same information is included in the RSAW is not the drafting team's decision. The determination of the final RSAW content belongs to the RSAW Task Force, the Regional Entities and NERC compliance groups. The draft RSAW will be reviewed by the RSAW Task Force and all comments submitted on the RSAW will be evaluated prior to the RSAW being finalized. The drafting team appreciates your understanding of the fundamental differences between the functional testing of RAS (performance evaluation of the scheme) versus maintenance of Protection System (maintaining components; i.e., relays, etc.). The drafting team contends that Requirement R8 should remain in PRC-012-2, as is.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Comment	
The list of qualifications for the designation of limited impact states that a limited impact RAS cannot cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. The	

term angular instability needs to be clarified further. Currently it implies that if the RAS was installed to prevent a 40 MW generator from becoming unstable, then it cannot be designated as limited impact. The term should be qualified as follows: system angular instability. This would give the RC the leeway to judge that a small unit going unstable would not negate the designation limited impact.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The drafting team avoids the use of adjectives such as "widespread" because of the ambiguity those terms introduce. The drafting team maintains that the "BES" qualifier in the statement regarding the limited impact designation modifies all of the conditions that follow; i.e., Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, and unacceptably damped oscillations. As you suggest, the instability of a single generating unit or small generating plant would not be indicative of an unstable or unreliable BES; however, the RC is the final arbiter for determining whether the RAS qualifies for limited impact status based upon review of the Attachment 1 information.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Comment	
ERCOT is supportive of the "limited impact" RAS designation, and is also supportive of a periodic evaluation of RAS to determine if these still qualify for the limited impact designation. However, ERCOT disagrees with the language of requirement subpart 4.1.3. Clarification on the intention of 4.1.3 in this context is requested. A Planning Coordinator (PC) with limited impact RAS (ex. a RAS set up to reduce BES flows by ramping down or tripping generation) should be allowed discretion to utilize screening studies as a threshold test to determine the necessity of evaluating a RAS for uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. For limited impact RAS that only have local impacts, 4.1.3 as written requires costly and unnecessary studies. ERCOT suggests that the SDT consider imposing a MW threshold for each interconnection below which the PC would be required to conduct only a power flow study. Alternatively, ERCOT requests clarification—in either 4.1.3 itself or in the rationale—that the PC has	

discretion in the type of studies it can use to satisfy the evaluations required to determine if the reliability impact of the RAS has changed over time.

ERCOT also asks for clarification on the "Supporting Documentation for RAS Review" in Attachment 1. The introductory statement in Attachment 1 implies that the Reliability Coordinator (RC) has discretion in determining exactly what information it would like to receive from an RAS-entity with the statement "If an item on this list does not apply to a specific RAS, a response of "Not Applicable" for that item is appropriate." The RAS-entity and the RC typically work together to determine what is required to approve an SPS or a RAS. The RC's discretion in determining what information a RAS-entity must submit under Attachment 1 is sufficient for the evaluation of the RAS.

ERCOT suggests the SDT make the RC's discretion explicit through the following language modification to the Attachment 1 introduction:

"The following checklist identifies important Remedial Action Scheme (RAS) information for each new or functionally modified RAS that the RAS-entity must document and provide to the reviewing Reliability Coordinator(s) (RC), *as required by the RAS-entity's Reliability Coordinator*"

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

PRC-012-2 is a results-based standard and not a prescriptive one; it is not the intent of the drafting team to specify how the PC provides the desired reliability objective of Requirement 4, Part 4.1.3. The PC can use its discretion regarding the methodology used to evaluate the RAS. The drafting team modified the Rationale for Requirement R4 to state: "Requirement 4, Part 4.1.3 explicitly requires the periodic evaluation of limited impact RAS to verify the limited impact designation remains applicable; the PC can use its discretion as to how this evaluation is performed."

The drafting team maintains that the RAS-entity can decide what information in Attachment 1 is "Not Applicable." For example, Item II.4 concerns "Information regarding any future System plans that will impact the RAS." The RAS-entity may not have any future plans which impact the RAS; therefore, a response of "Not Applicable" is appropriate for this item. The drafting team declines to make the suggested change.

Andrew Pusztai - American Transmission Company, LLC - 1

Answer	No
Comment	

ATC has several recommendations for improvement or clarification on the draft Standard, for consideration by the SDT as listed below:

- R4.1.3 and R4.1.4 – These requirements refer to 'single component malfunction' and 'single component failure' respectively. However, the standard does not contain any identification or clarification of which types of components must be included and which may be excluded in RAS evaluations. This deficiency could be addressed by including text in the Supplemental Material section under Requirement 4 that the drafting team developed for a response in its Consideration of Comments for Draft 1 of PRC-012-2.

"An exhaustive list of components is not practical given the variety that could be applied in RAS design and implementation. See Item 4a in the Implementation Section of Attachment 1 in the Supplemental Material section for typical RAS components for which redundancy may be considered. The RAS-entity should have a clear understanding of what components were applied to put a RAS into service and which were already present in the system before a RAS was installed. The RC will make the final determination regarding which components should be regarded as RAS components during its review".

- R5 – This requirement does not obligate RAS-entities to provide their results of the operational performance analysis of a RAS event to impacted Transmission Planners and Planning Coordinators. However, this action should be proposed in the Supplemental Material section.
- R6 – This requirement does not obligate RAS-entities to provide their Corrective Action Plans to impacted Transmission Planners and Planning Coordinators. However, this action should be proposed in the Supplemental Material section.
- R8 - The purpose of Version 6 of PRC-005 was to consolidate all maintenance and testing of relays under one Standard. Having RAS testing within PRC-012-2 would be contrary to that end. ATC proposes to address this concern as follows:

Functional testing of RAS (as stated in Requirement 8 of PRC-012-2) is a maintenance and testing activity that would be better included in the PRC-005 standard. The present PRC-005-6 Reliability Standard is the maintenance standard that replaces PRC-005-1, 008, 011 and 017 and was designed to cover the maintenance of SPSs/RASs. However, the current Reliability Standard PRC-005-6 lacks intervals and activities related to non-protective devices such as programmable logic controllers. ATC recommends that a requirement for

maintenance and testing of non-protective RAS components be added to a revision of PRC-005-6, rather than be an outlying maintenance requirement located in the PRC-012-2 Standard. If the requirement is not removed and placed in PRC-005 standard, then we suggest that wording be added to R8 to refer the entity to meet the maintenance and testing interval obligations in the latest version of the PRC-005 standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The drafting team included language as you suggested in the Supplemental Material section of the draft standard for Requirement R1. It is not the intent of Requirement R4 that the PC performing the evaluation examine the physical implementation of the RAS, but rather to assess the System impacts of a failure to operate or an inadvertent operation. If redundant components were used to implement the RAS such that a single component failure would not prevent the RAS from operating, this would be confirmed by the RC during the initial review and then verified by subsequent functional testing, and should not need to be re-examined during the periodic evaluation per Requirement R4. However, if the RAS is designed to meet the “failure to operate” or “inadvertent operation” objectives by over-arming of load or alternate actions, the continued effectiveness of these alternative actions should be evaluated. There is nothing in the standard preventing the RAS-entity from sharing the results of its operational analysis with their TP or PC. It is anticipated that in many cases, the TP or PC will be involved in performing the analysis. The Rationale for Requirement R5 notes that RAS-entities may need to collaborate with their associated Transmission Planner to comprehensively analyze RAS operational performance. The drafting team declines to make the suggested change. There is nothing in the standard preventing the RAS-entity from sharing its CAP with their TP or PC. It is anticipated that in many cases, the TP or PC will be involved in developing the CAP. The Rationale for Requirement R6 notes that the RAS-entity may request assistance with CAP development from other parties such as its Transmission Planner or Planning Coordinator. The drafting team declines to make the suggested change. As stated in the current version of PRC-005-6, the purpose of the Standard is: “To document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric	

System (BES) so that they are kept in working order." The only applicability for RAS components in the current version is under the Facilities section 4.2.4 with "Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability". As a result, PRC-005-6 is not applicable to non-Protection System components, such as RAS controllers. The drafting team has identified various components that may be used in RAS that are not Protection Systems, such as programmable logic controllers (PLCs), personal computers (PCs), multi-function programmable relays used as a PLC, remote terminal units (RTUs), and logic processors. Given the potential impact RAS may have on the BES, the drafting team contends that functional testing is necessary to maintain BES reliability. The reliability objective of Requirement R8 is to maintain the non-Protection System components of a RAS; i.e., the controllers (programmable logic controllers (PLCs), personal computers (PCs), multi-function programmable relays, remote terminal units (RTUs), and logic processors), and to verify the overall performance of the RAS through functional testing. Functional tests validate RAS operation by ensuring System states are detected and processed, and that actions taken by the controls are correct and occur within the expected time using the in-service settings and logic (functional testing by default operates the processing logic and infrastructure of a RAS). Functional testing should not be confused with the component focused maintenance of PRC-005 Protection System Maintenance. PRC-005 is not applicable to non-Protection System components such as RAS controllers. RAS designated as limited impact have functional testing intervals of up to twelve full calendar years. However, all other RAS have up to six full calendar year intervals because of the higher risk they pose to negatively impact BES reliability should they operate incorrectly or fail to operate. The drafting team recognizes that PRC-005 extends the maintenance interval for monitored multifunction programmable relays to twelve calendar years; however, the drafting team asserts that the inadvertent operation or failure of a RAS subject to the six year functional test interval poses too much risk to the reliability of the BES to extend the test interval beyond six years.	
Douglas Webb on Behalf of Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co. - 3, 6, 5, 1	
Answer	No
Comment	
Kansas City Power & Light Company appreciates this opportunity to share its comments regarding concerns the company has with the proposed revisions to the Standard. As used in the proposed revisions to Standard PRC-012-2, the term "limited impact" creates an ambiguous enforceable provision and needs to be a defined NERC Glossary term to establish a clear compliance threshold.	

The Standard Drafting Team (SDT) is empowered by the NERC Standards Process Manual (SPM) to "…propose to add, modify, or retire a defined term in conjunction with the work it is already performing." SPM, Sec. 5 Preamble. We respectfully request the SDT exercise that authority to define "limited impact" for the following reasons.

"Limited impact" establishes an enforceable provision: The proposed revisions use "limited impact" in the language of the Requirements and attachments to the Standard that are incorporated by reference. By the regular use of the term, and the context in which it is used, a conclusion is easily drawn: The term is material to the Standard and required to evaluate compliance and, ultimately, enforcement of the Standard.

"Limited impact" creates an uncertain compliance obligation: The term "limited impact" is undefined and ambiguous and, as such, creates uncertainty in an entity's compliance obligation. The word "limited" suggests a range of values. When used with "impact," the range of values is used to affect the determination of the degree of impact. The proposed revisions to the Standard seek to establish the range of values in multiple ways. First, by referencing information found in the stated underlying source of the term, WECC and NPCC classification schemes; secondly, offering an explanation what is intended by the term; third, explaining what the term is not intended to reflect; and, lastly, a lengthy discourse on the term, as found in the Attachments. Taken together, all the information may seem to provide guidance as to the meaning of the term, "limited impact," but in the end the term remains undefined and creates a compliance obligation that is unclear and promotes a spectrum of interpretations as to what values fall within the "limited" range.

Policy promotes relevant Regional Defined Terms be considered for the NERC Glossary Term: The NERC Standards Process Manual (SPM) states:

"Some NERC Regional Entities have defined terms that have been approved for use in Regional Reliability Standards, and where the drafting team agrees with a term already defined by a Regional Entity, the same definition should be adopted if needed to support a NERC Reliability Standard." SPM Sec. 5.1.

The proposed revisions to the Standard provide that the source of the term "limited impact" is taken from the WECC and NPCC classification schemes. Whether the term is a regionally defined term by WECC and NPCC or not, the spirit of the SPM is to apply terms equally, that if a term is used by Regional Entities in a North American Standard, then it is appropriate for the term be considered for adoption as a defined term to support that Standard.

Below is a Catalog of the Term "limited impact" as used in Proposed PRC-012-2 Standard

The Standard's language uses "limited impact" in Requirements R4 and R8, and multiple times in the three attachments that are incorporated by reference in the Standard.

WECC and NPCC Classification Schemes—R4 Rationale cites to the WECC and NPCC classification schemes as how the "…limited impact designation is modeled…;" *Technical Justification* for the term "limited impact" states, "Because the drafting team modeled the limited impact designation after the WECC and NPCC classifications…"

Description of what the term, "limited impact," is not—R4.1.3. Footnote to "limited impact." See also Att. 1, Sec. I.4.g Footnote to "limited impact"; Att. 2, Sec. I.6 Footnote to "limited impact"; Att. 3, Sec. 7 Footnote to "limited impact"; *Technical Justifications for Attachment 1 Content Supporting Documentation for RAS Review*, Sec. I.4.g Footnote to "limited impact"; *Technical Justifications for Attachment 3 Content*, Sec. 7 Footnote to "limited impact."

"Limited impact" Citations in Standard—The use of the term "limited impact" in R4; R8; Att. 1, Sec. I.4.g; Att. 1, Sec. II.5; Att. 1, Sec. II.6; Att. 1, Sec. III.4; Att. 2, Sec. I.6; Att. 2, Sec. I.7; Att. 2, Sec. II.2; Att. 3, Sec. 7; *Supplemental Material*, R4, R8; *Technical Justifications for Attachment 1 Content Supporting Documentation for RAS Review*, Sec. I.4.g, Sec. II.5, Sec. II.6, Sec. III.4; and *Technical Justifications for Attachment 3 Content*, Sec. 7.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

The drafting team disagrees with the premise that the term limited impact creates an ambiguous enforceable provision and should be a defined term in the Glossary of Terms Used in NERC Reliability Standards. The drafting team maintains that the general description and explanatory language regarding the limited impact designation does not rise to the level of a definition that should be included in the Glossary of Terms Used in NERC Reliability Standards; instead, it provides high-level guidance for the RC to consider during the RAS review. The Reliability Coordinator has responsibility for the reliability of BES operations within its RC Area and consequently has the responsibility to review and approve each RAS before it is implemented in its RC Area. Furthermore, the RC has the discretion to designate applicable RAS as limited impact, on a case-by-case basis. The drafting team asserts an entity's compliance obligations regarding a limited impact RAS are clear and unambiguous. For each RAS designated by the RC as limited impact, the entity must be compliant with each applicable requirement of PRC-012-2.

The drafting team agrees that the term limited impact is not defined. The drafting team maintains that the general description and explanatory language regarding the limited impact designation provides high-level guidance for the RC to consider during the RAS review. WECC and NPCC were cited because those are the only two Regions that classified RAS based upon certain criteria. The System Protection and Control Subcommittee-System Analysis and Modeling Subcommittee team also recognized these Regional classifications and made similar albeit different recommendations. The drafting team considered the attributes of each of these Regional classifications in creating the guidance for limited impact designation. The limited impact designation is applicable on a continent-wide basis via NERC Reliability Standard PRC-012-2.

Oshani Pathirane on Behalf of Payam Farahbakhsh, Hydro One Networks, Inc. - 1, 3

Answer	No

Comment

Comment 1 - R4.1.5 - In TPL-001-4, loss of a single line due to a fault is “Single Contingency” (Category P1), but the failure of a breaker or protection relay following that single contingency is recognized as “Multiple Contingency” (Category P4 and P5) and has a different performance requirement compared to the initial P1 event. Similarly, the system performance following a RAS failure to operate after an event should not be required to meet the exact same requirements as those for the original event.

Therefore, we suggest deleting 4.1.5 and instead revising 4.1.4 to say “Except for limited impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction, or a single component failure in the RAS, when the RAS is intended to operate, satisfies all of the following:”

Comment 2 - R5.1 – The wording “*participate*” which is used in the R5.1 does not define accountability or a definite action. For consistency, we suggest using verbiage similar to that used in PRC-004-4’s description of accountabilities in the case of owning Shared Protection Systems.

Comment 3 - R5.1.3 & R5.1.4 are related to performance of RAS and its impact on BES system. This assessment is better suitable for the PC or RC to conduct

Comment 4 – In R5.2, in case of a RAS being owned by more than one RAS-Entity, it is unclear which RAS-Entity is accountable to communicate with the RC and maintain evidence. The requirement needs to clearly identify who is accountable for what, similarly to how PRC-004-4 describes accountabilities in case of Shared Protection System.

Comment 5 – Similar to R5, the wording "*participate*" used in R6 does not define accountability or a definite action. For consistency, we suggest using verbiage similar to that used in PRC-004-4's description of accountabilities in the case of owning Shared Protection Systems.

Comment 6 - Similar to comment R5 above, R6 does not clearly define accountabilities in the case of a RAS being owned by more than one RAS-Entity. In such case, which Entity is accountable to communicate with the RC and maintain evidences?

Comment 7 – It is unclear from the wording whether the RAS-entity would "Participate in analyzing the RAS operational performance" with the RC, or only mutually agree upon a schedule for such activity with the RC.

Comment 8 - R8 is vague and subject to interpretation. There are references in the supplemental material that suggest maintenance checking all of the logic in a PLC on a periodic basis is required and yet in PRC-005, it's clear that there is no need to perform periodic maintenance on relay logic. For monitored components, such as microprocessor relays, the "*verification of settings [as] specified*" in PRC-005 (i.e., performing a settings compare) should be sufficient rather than implying that all logic needs to be re-verified. For RAS not designated as limited-impact, R8 does not distinguish between monitored and unmonitored components of the RAS such as in PRC-005, which would allow a RAS-entity to have a 12-year maintenance interval for monitored components.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

COMMENT 1: The drafting team is not persuaded by the reasoning/example provided by the commenter to advocate that System performance after a RAS failure to operate should be different (i.e. less stringent) than the System performance requirement for the original contingency event for which the RAS is intended to operate. The drafting team asserts that the RAS failure to operate event cannot be considered analogous to the breaker or protective relay failure to operate events (i.e. P4 and P5 contingencies) in Table 1 of TPL-001-4. This is because implementing/installing a RAS is essentially the mitigation identified in the Corrective Action Plan required by TPL-001-4 to demonstrate meeting the System performance for planning events. Please note that several examples of corrective actions listed in TPL-001-4, Requirement 2, Part 2.7.1 are fully aligned with the RAS definition.

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, or removal of Protection Systems or Special Protection Systems

- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.

Allowing less stringent system performance for failure of RAS (except for limited impact RAS) to operate due to single component failure would essentially be equivalent to rendering the RAS an inadequate mitigation for the very same System performance deficiencies identified in TPL-001-4 that triggered the RAS implementation. Therefore, the System performance due to a RAS failure to operate must be the same as for the original contingency event for which it was designed, and it may be a higher System performance bar than is allowed for inadvertent RAS operation for certain contingency events. Consequently, the drafting team declines to merge Requirement R4, Parts 4.1.4 and 4.1.5.

COMMENTS 2, 5, and 6: The drafting team is charged with assigning the requirements of the new standard to the specific users, owners, and operators of the Bulk-Power System while incorporating the reliability objectives of all the RAS-related standards. In drafting this standard, the drafting team has worked diligently to minimize the changes that will be required from the existing processes. The drafting team recognizes that RAS with multiple owners inherently require coordination among all the participating RAS-entities from the first conceptual design through construction to operations, testing, maintenance and retirement. For purposes of PRC-012-2, when a RAS has more than one owner, each RAS-entity is obligated to participate in the various activities identified by the requirements to the extent of its ownership. Collaboration, coordination, and communication between and among entities regarding RAS issues helps to ensure efforts are not duplicated and best serves reliability by promoting awareness. For purposes of creating efficiencies, the drafting team maintains registered entities that currently share ownership of a RAS (RAS-entities) are in some manner already communicating, sharing information, and coordinating RAS tasks such as operations analysis, Corrective Action Plan (CAP) development, and functional testing. The drafting team is confident that entities will continue to do this after this standard is effective and that entities will communicate with each other if there is any question or doubt of responsibility surrounding any requirement. From the NERC Drafting Team Reference Manual, Version 2, January 2014, Attachment A — Verbs Used in Reliability Standards: “When developing a new or revised standard, DTs should try to use terms that have already been defined or terms that are already used in other Reliability Standards to achieve a high degree of consistency between standards. To that end, the Standards staff, working with key DT members, put together the following list of verbs and their associated definitions. These verbs are all used in requirements in existing Reliability Standards. This verb list and its definitions are not in the Glossary of Terms used in NERC Reliability Standards but these verbs and their definitions should serve as a reference for DTs who are trying to minimize the introduction of new terms into Reliability Standards. Participate is defined as “To take part or share in something.”

COMMENT 3: The RAS-entity(ies) may need to collaborate with its associated Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation was triggered correctly (Part 5.1.1), responded as designed (Part 5.1.2), and that the resulting BES response (Parts 5.1.3 and 5.1.4) was consistent with the intended functionality and design of the RAS. However, similar to the responsibility assigned to the RAS-entity and the possible collaboration with the TP in R1, the drafting team contends that the RAS-entity is the suitable entity responsible for compliance to R5.

COMMENT 4: The term RAS-entity is defined in the Applicability as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If all of the RAS (RAS components) has a single owner, then that RAS-entity has sole responsibility for all the activities assigned within the standard to the RAS-entity.

The standard does not stipulate compliance methods. RAS-entities have the option of collaborating to fulfill their responsibilities for each applicable requirement. Such collaboration and coordination should promote efficiency in achieving the reliability objectives of the requirements; however, the individual RAS-entity must be able to demonstrate its participation for compliance. As an example, the individual RAS-entities could collaborate to produce and submit a single, coordinated Attachment 1 (acknowledging all RAS-entities that participated in the provision of data) to the reviewing RC pursuant to Requirement R1 to initiate the RAS review process.

COMMENT 7: The drafting team contends that the wording of Requirement R5 clearly states that each RAS-entity shall participate in the analyses of its RAS operations (with other RAS-entities, not the RC). The RAS-entity must perform the analyses and provide it to its RC only if deficiencies in the RAS are found.

COMMENT 8: The reliability objective of Requirement R8 is to maintain the non-Protection System components of a RAS; i.e., the controllers (programmable logic controllers (PLCs), personal computers (PCs), multi-function programmable relays, remote terminal units (RTUs), and logic processors), and to verify the overall performance of the RAS through functional testing. Functional tests validate RAS operation by ensuring System states are detected and processed, and that actions taken by the controls are correct and occur within the expected time using the in-service settings and logic (functional testing by default operates the processing logic and infrastructure of a RAS). Functional testing should not be confused with the component focused maintenance of PRC-005 Protection System Maintenance. PRC-005 is not applicable to non-Protection System components such as RAS controllers. RAS designated as limited impact have functional testing intervals of up to twelve full calendar years. However, all other RAS have up to six full calendar year intervals because of the higher risk they pose to negatively impact BES reliability should they operate incorrectly or fail to operate. The drafting team recognizes that PRC-005 extends the maintenance interval for monitored multifunction programmable relays to twelve calendar years;

however, the drafting team asserts that the inadvertent operation or failure of a RAS subject to the six year functional test interval poses too much risk to the reliability of the BES to extend the test interval beyond six years.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Comment	

Regarding R4:
BPA believes that limited impact RAS should not be singled out to be exempt from meeting the performance requirements.

While the level of review could be lower, BPA believes a “limited impact” RAS should still be designed such that failure or inadvertent operation of the RAS does not have an adverse impact on an adjacent TP or PC beyond the performance criteria for which the system is planned.

Additionally, regarding R2:
BPA maintains that allowing an RC up to four months to complete the RAS review is longer than necessary and not in line with current practice, which requires the information to be submitted to the RAS Reliability Subcommittee two weeks prior to the meeting where it will be reviewed and approved or disapproved. Allowing four months could delay energization of new or functionally modified RAS by 14 weeks.

BPA also remains concerned by the term “mutually agreeable” and how it will be applied.

Likes 0	
Dislikes 0	
Response	

The drafting team included the limited impact recognition in the standard to capture the intent of the RAS classification as suggested in the SPCS-SAMS report. The limited impact designation is intended to recognize that RAS vary in complexity and impact on the BES. All RAS (limited impact and others) must be considered in TPL assessments. In no instance does the limited impact designation exempt a RAS from satisfying TPL-001-4 performance requirements.

The drafting team asserts that the RC will take such impacts into account in its determination of limited impact status. Any RAS that causes adverse impacts on adjacent systems beyond the performance criteria for which the RAS is planned strongly implies a scheme exhibiting more than limited impact.

The time frame of four full calendar months is consistent with current utility and regional practices. The drafting team wrote the requirement to allow for time intervals longer or shorter than four full calendar months by including the phrase "mutually agreed upon schedule" among the affected parties. All RCs are required to have situational awareness of and responsibility for operational issues adversely affecting BES reliability. Both awareness and responsibility provide an incentive to pre-empt and/or mitigate such operational issues and any related operation limits when possible. When a RAS-entity's Attachment 1 filing identifies such near-term operational issues and demonstrates how the proposed RAS implementation would address them, it is difficult to believe that the RC would choose to wait another 14 weeks to complete the RAS review when it is clear that delaying the RAS implementation would adversely impact the BES reliability or capability.

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Comment	

As a general comment, HQT is in the view that PRC-012-2 should not address the details of how RAS entities should perform their analysis according to requirement R8. Each RAS entity has systems operation applicability adapted to their particular topology and some systems cannot withstand invasive actions (maintenance and testing activities) because of such topology. Therefore, PRC-012-2 requirements should allow a certain level of flexibility to this effect, which HQT has commented further below.

Regarding comments specific to the wording of PRC-012-2 requirements, Footnote 2 in Attachment 1 is a definition, and it should be treated as such. Also, the fourth bullet under footnote 2 reads "Changes to RAS logic beyond correcting existing errors" needs clarification. What are the existing errors? The RAS should not have been approved if there were errors, and if it was approved with the errors then those errors might be preventing the RAS from meeting its intended functionality. Suggest removing this bullet, and revising the second bullet to read: Changes to the logic that affects the actions the RAS is designed to initiate. The preceding is also applicable to Footnote 4 on page 25 for Attachment 2. Footnote 3 on page 23, footnote 5 on page 25, and footnote 6 on page 27 are not needed because of the first comment above regarding Requirement R4.

In addition, on page 27 in the Supplemental Material section, shouldn't the Planning Coordinator, because of its wide-area view be included in determining if a RAS can be designated limited impact?

In the two paragraphs preceding Requirement R1 on page 29 of the Supplemental Material section it should be emphasized that the actions of the limited-impact RAS do not lead to the more severe BES consequences that would preclude a RAS from being defined a limited-impact RAS. On page 34, same comment as in the preceding paragraph concerning "Changes to RAS logic beyond correcting existing errors". On page 34 of the Supplemental Material section in the third paragraph under Requirement R4, shouldn't the Planning Coordinator, because of its wide-area view, be involved in the designation of a RAS as limited-impact?

Also, on page 45 for the Technical Justifications for Attachment 1 Content Supporting documentation for RAS Review, comments pertaining to footnote 8 the same as above for the comments regarding footnote 2.

HQT also has specific comments on requirements R5 and R8 as follows.

Firstly for NPCC, the Type '3' should be written 'III'. Also, VSL of R5 requests to 'perform' analysis. R5 mentioned only to 'participate'. In the Rationale section, at R4: references to Parts 4.1.3.1-4.1.3.5 should be corrected to 4.1.4.1-4.1.5. HQT is in the opinion that Lower VSL of R7 should be High VSL because RC must be notified if CAP has changed since changes in action or timetables may require the RC to intervene to maintain reliability.

Secondly, HQT suggests to remove footnote 3 on page 23, footnote 5 on page 25, and footnote 6 on page 27 by modifying the Applicability section 4.2.1 in section 4.2 entitled Facilities by the following: ''Remedial Action Schemes (RAS) not designated as "limited impact". A RAS designated as "limited impact" cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.''

Thirdly, regarding requirement R8, as mentioned in HQT's general comments above, as for protection systems, invasive actions (maintenance and testing activities) may introduce a higher number of misoperations which can stress the electrical system. As recognized in PRC-005, new technology may offer the benefits to avoid this type of activities. Thus, from a reliability perspective, a RAS Entity should decide which technique is most appropriate to verify the RAS integrity according to the complexity of their design. If for some reason, a RAS entity would prefer to dynamically extract and compare the settings file of the RAS components instead of doing functional tests, it could be another acceptable method to meet the intent of requirement of R8 without doing invasive actions that could adversely affect the reliability of the system.

HQT notes that there is actually no difference made in PRC 005 for limited impact RAS components. However, HQT agrees with PRC 012-2 regarding the fact that limited impact RAS represents a low reliability risk to the BULK power system. For those RAS, HQT agrees that less stringent criteria can be applied. In PRC-005, there is no mention of limited impact RAS components, this concept should be incorporated within the standard.

Finally, in light of the above comments, HQT is of the view that the maximum allowable interval between functional tests should be twelve full calendar years for RAS that are not designated as limited impact RAS.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

PRC-012-2 Requirement R8 requires the periodic completion of functional tests to verify the overall performance of the RAS but is not prescriptive regarding the methods used to perform the tests. As described in the Rationale box and Supplemental Material section of the standard for Requirement R8, entities have the flexibility to utilize end-to-end or overlapping segment testing.

Regarding the wording of footnote 2 and the term “functionally modified,” it is intended to be a list of examples of RAS modifications to provide guidance to responsible entities. An example of an existing error is a previously undetected logic error made during implementation of the RAS. The drafting team declines to make the suggested change.

The Planning Coordinator (PC) or Transmission Planner (TP) is the entity that performs the planning studies and most often identifies the need for a RAS and/or determines the necessary RAS characteristics, including the proposal and justification for limited impact designation. These studies are included in the Attachment 1 information supplied by the RAS-entity to the Reliability Coordinator (RC) for RAS review and approval. Because the PC is involved in developing the studies and/or evaluations, the drafting team did not include them as mandatory participants in the RAS review and approval process where they would be responsible for judging and approving their own work. Moreover, the drafting team contends that the limited impact description within the standard is sufficient to address the case where the RAS actions lead to severe BES consequences.

The drafting team is satisfied with the language pertaining to limited impact RAS and its location in the footnote. The drafting team sees no benefit by including limited impact RAS in the Applicability/Facilities section of the standard and declines to make the suggested change.

The drafting team corrected the references to NPCC Type III. The drafting team declines to make the suggested change in the VSLs for Requirement R5. The use of "performed" is correct, "participate" is incorporated by the phrase "in accordance with Requirement R5." The drafting team corrected the reference to the Parts (4.1.4.1-4.1.4.5) in the Rationale for Requirement R4. The drafting team disagrees with the suggested change to the VSL for Requirement R7. Failing to update the CAP or not notifying the RC following a CAP update or completion does not meet the criteria established for a Severe VSL. The drafting team agrees that PRC-005 does not make a distinction for components related to limited impact RAS. The limited impact recognition is referenced only in PRC-012-2. The reliability objective of Requirement R8 is to maintain the non-Protection System components of a RAS; i.e., the controllers (programmable logic controllers (PLCs), personal computers (PCs), multi-function programmable relays, remote terminal units (RTUs), and logic processors), and to verify the overall performance of the RAS through functional testing. Functional tests validate RAS operation by ensuring System states are detected and processed, and that actions taken by the controls are correct and occur within the expected time using the in-service settings and logic (functional testing by default operates the processing logic and infrastructure of a RAS). Functional testing should not be confused with the component focused maintenance of PRC-005 Protection System Maintenance. PRC-005 is not applicable to non-Protection System components such as RAS controllers. RAS designated as limited impact have functional testing intervals of up to twelve full calendar years. However, all other RAS have up to six full calendar year intervals because of the higher risk they pose to negatively impact BES reliability should they operate incorrectly or fail to operate. The drafting team recognizes that PRC-005 extends the maintenance interval for monitored multifunction programmable relays to twelve calendar years; however, the drafting team asserts that the inadvertent operation or failure of a RAS subject to the six year functional test interval poses too much risk to the reliability of the BES to extend the test interval beyond six years. The drafting team declines to make the suggested change to the functional testing interval.	
Larry Heckert on Behalf of Kenneth Goldsmith, Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Comment	

Alliant Energy supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see the drafting team's responses to the referenced comments.	
Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6	
Answer	Yes
Comment	
In the Supplemental Material, on p. 30 of 55 of the redlined document, please clarify what is meant by "…affected by the contingency." Specifically, is this the contingency that would require RAS operation, or is the contingency the overloading of the BES Element? Outside of the scope of the survey question -- in Measurement M5, please consider changing "…with participating RAS-entities and…" to "…with participating RAS-entities, if applicable, and…"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. This is the Contingency which results in an overload that the RAS is intended to mitigate. The drafting team does not see any additional benefit from your suggested change. No change made to the standard.	
David Greene - SERC Reliability Corporation - 10, Group Name SERC DRS	

Answer	Yes
Comment	

SERC DRS suggests a revision as to what constitutes a limited impact RAS. Currently, the language in the standard suggests that an RAS considered to be limited impact cannot:

"cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations"

We suggest revising the above language by inserting the term "widespread" before angular instability. Angular instability could be experienced by just one generating unit going out of sync. A single generating unit becoming unstable is not indicative of an unstable or unreliable BES, and we do not believe that this should remove an RAS from limited impact consideration.

The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Dynamics Review Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

The drafting team avoids the use of adjectives such as "widespread" because of the ambiguity those terms introduce. The drafting team maintains that the "BES" qualifier in the statement regarding the limited impact designation modifies all of the conditions that follow; i.e., Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, and unacceptably damped oscillations. As you suggest, the instability of a single generating unit or small generating plant would not be indicative of an unstable or unreliable BES; however, the RC is the final arbiter for determining whether the RAS qualifies for limited impact status based upon review of the Attachment 1 information.

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)

Answer	Yes
Comment	

However, the NSRF proposes including the following opinion in the Supplemental Material section: R4 – This requirement refers to 'single component malfunction' and 'single component failure'. However, the standard does not contain any qualification of which types of components must be included in RAS evaluations or what entity ultimately makes the component inclusion determination. Therefore, to avoid making elaborate component inclusion qualifications or letting there be uncertainty over which entity makes the final component inclusion determination, add text to the Supplemental Material section such as, "The RC will make the final determination regarding which RAS components are included in the RAS evaluation during its review".	
Likes 0	
Dislikes 0	
Response	
The drafting team included language as you suggested in the Supplemental Material section of the draft standard for Requirement R1. It is not the intent of Requirement R4 that the PC performing the evaluation examine the physical implementation of the RAS, but rather to assess the System impacts of a failure to operate or an inadvertent operation. If redundant components were used to implement the RAS such that a single component failure would not prevent the RAS from operating, this would be confirmed by the RC during the initial review and then verified by subsequent functional testing, and should not need to be re-examined during the periodic evaluation per Requirement R4. However, if the RAS is designed to meet the "failure to operate" or "inadvertent operation" objectives by over-arming of load or alternate actions, the continued effectiveness of these alternative actions should be evaluated.	
William Temple on Behalf of Mark Holman, PJM Interconnection, L.L.C. - 2	
Answer	Yes
Comment	
PJM supports the comments submitted by the ISO/RTO Council.	
Likes 0	
Dislikes 1	Public Service Enterprise Group , 1,3,5,6, Koncz Christy
Response	
Thank you for your comment.	

Please see the drafting team's responses to the referenced comments.

John Pearson on Behalf of Michael Puscas, ISO New England, Inc. - 2	
Answer	Yes
Comment	
Requirement R4.1.3 includes language from the associated footnote verbatim. The language in the footnote should be deleted. The requirement also seems to define a limited impact RAS. The NERC Glossary should include the definition of a limited impact RAS.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The drafting team disagrees that the footnote should be deleted and that Requirement R4, Part 4.1.3 is redundant with the footnote. The drafting team has determined that the general description of limited impact RAS, which only describes actions to which a RAS cannot cause or contribute and be considered limited impact, does not rise to the level of a definition that should be included in the Glossary of Terms Used in NERC Reliability Standards. Rather, the explanation of a limited impact RAS is only high level guidance that must be considered by an RC when using its discretion and its wide area perspective to determine whether a limited impact designation is appropriate for a given RAS.	
Erika Doot - U.S. Bureau of Reclamation - 5	
Answer	Yes
Comment	
The Bureau of Reclamation agrees with the changes proposed by the drafting team.	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No HQ and Dominion	
Answer	Yes
Comment	
Footnote 1 in Requirement R4 is not needed as written. It just reiterates the wording of sub 4.1.3. Same applies to footnote 9 on page 46 as the wording in sub 4.1.3 pertains to the entire document. An appropriate footnote would read that NPCC Type 3 classification and the WECC LAPS classifications will be recognized as limited-impact RAS.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The drafting team disagrees that the footnote should be deleted and that Requirement R4, Part 4.1.3 is redundant with the footnote. The drafting team has determined that the general description of limited impact RAS, which only describes actions to which a RAS cannot cause or contribute and be considered limited impact, does not rise to the level of a definition that should be included in the Glossary of Terms Used in NERC Reliability Standards. Rather, the explanation of a limited impact RAS is only high level guidance that must be considered by an RC when using its discretion and its wide area perspective to determine whether a limited impact designation is appropriate for a given RAS. The drafting team declines to make the suggested change to the footnote.	
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	

Response	
Michael DeLoach - AEP - 3	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Michael DeLoach - AEP - 3	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	

Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC-ISONE	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	

Response	
Allie Gavin on Behalf of Michael Moltane, International Transmission Company Holdings Corporation - 1	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	

Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	

Response
Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Comment	

Texas RE noticed the SDT did not specifically address its comments submitted on January 8, 2016. Texas RE respectfully requests the SDT to respond to its comments.

As previously stated in comments submitted on January 8, 2016, Texas RE does not agree with the provision that a RAS can be designated as "limited impact". Texas RE recommends the SDT reconsider and treat all RASes, that affect the reliability of the Bulk Electric System (BES) equally.

However, if the SDT elects to keep the limited impact designation, Texas RE is concerned the proposed criteria for determining a "limited impact" RAS is vague and ambiguous (e.g. "… BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations). Absent clear criteria, the RC may designate certain RASes as limited impact that would be more properly characterized as a RAS. Because limited impact RASes are subject to reduced reliability-related considerations by the Reliability Coordinator (i.e. Attachment 2) and limited evaluation performed by the Planning Coordinator (i.e. Requirement 4), the improper characterization of RASes may lead to potential reliability gaps on the BES.

Texas RE inquires as to what the SDT used as technical basis (such as industry reports, recommendations from task forces or working groups, field studies, etc) in determining to create a requirement to designate limited impact RASes.

TPL-001-4

In Requirement R4.1.5, Texas RE is concerned the planning requirements in TPL-001-4 do not distinguish between limited impact RAS and RAS. For example under TPL-001-4, a PC must consider an operation of a RAS, including a limited impact RAS, that results in an applicable Facility Rating being exceeded. Texas RE understands planning and RAS evaluation are separate obligations for the PC with separate requirements. However, the language in R4.1.5 specifically identifying the "same performance requirements" as defined in TPL-001-4 potentially blurs these two obligations with respect to limited impact RAS. Texas RE suggests eliminating the phrase "Except for limited impact RAS" in R4.1.5 so PRC-012-2 and TPL-001-4 cannot be interpreted to potentially conflict with each other.

Degraded RAS

Texas RE submitted comments on October 5, 2015 stating its concern there is no requirement to report the degraded RAS to the RC. The SDT responded:

The status of a degraded RAS is required to be reported (in Real-time) to the Transmission Operator via PRC-001, Requirement R6, then to the RC via TOP-001-3, Requirement R8. See Phase 2 of Project 2007-06 for the mapping document from PRC-001 to other standards regarding notification of RC by TOP if a deficiency is found during testing. Consequently, it is not necessary to include a similar requirement in this standard.

Texas RE does not agree this issue is handled in the standards identified by the SDT in its response. As an initial matter, TOP-001-3 R8 does not necessarily require the TOP to inform the RC. TOP-001-3 R8 is specifically limited to Emergencies, which do not necessarily include degradation of a RAS. Does the SDT envision treating all RAS degradations as Emergencies as defined by the NERC Glossary of Terms in order to trigger the TOP-001-3 R8 reporting obligations?

TOP-001-3 also uses the term “Transmission Operator Area” which, by definition, does not necessarily include DP and GO, which are “RAS-entities”, equipment if used in a RAS. This is a gap in reliability.

In addition, other related standards do not appear to require RAS-entities to report degraded RASes to the RC in all circumstances. For example, TOP-003-3 discusses having a data specification and distributing the data specification. However, this Standard does not explicitly include notification of actual degradation of a RAS to an RC or explicitly require entities to provide actual data. In particular, TOP-003-3 R3 states “Each Transmission Operator shall distribute its data specification to entities that have data required by the Transmission Operator’s Operational Planning Analyses, Real-time RAS monitoring, and Real-time Assessment.” Moreover, TOP-003-3 R3 explicitly covers the “Operations Planning” Time Horizon (not Real-time or Same-Day Operations). TOP-003-3 R5 also states “Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications…”. Again, under this Standard, there is no explicit requirement that entities provide the RC that is reviewing and approving the RAS the actual data regarding the “current Protection System and Special Protection System status or degradation that impacts System reliability.”

Misoperations

The definition of Misoperation that becomes effective on July 1, 2016 does not include RASes. Texas RE recommends clarifying R5 by defining misoperation to align with PRC-004-4. If misoperation is not defined, entities might not do the actions outlined in R 5.1. The

SCPS drafted a RAS template to describe misoperations which were never officially approved. Texas RE recommends adding a definition of misoperations for RASes in the Standard or NERC Glossary based on the SCPS RAS template and the language in R5.

Also, while reporting of Protection Systems Misoperations will be contained within the Section 1600 Data Request for PRC-004, neither PRC-012-2 nor the Section 1600 data request provides a corresponding reporting requirement for RAS misoperations to the Regional Entities or NERC. Texas RE recommends the SDT consider adding a requirement, either to PRC-012-2 or to the Section 1600 data request, for Registered Entities to report misoperations of RASes to regional entities.

Functional Testing – R8

Texas RE is concerned PRC-012-2 R8 does not address the scenario where a RAS is owned by different companies. In particular, PRC-012-2 R8, as currently drafted, does not require simultaneous testing each separately-owned component of the RAS-system simultaneously so that entities can verify that the RAS properly operates. For example, there are instances in Texas where a GO and TO own part of the same RAS. Under the current Standard language, the GO will test the receipt signal and the TO will test sending signal. However, there is no requirement for the GO and TO to coordinate the tests of their individual components to ensure that signal is sent and received. Put differently, although each individual component may be tested, there is no corresponding test of to ensure the entire RAS will operate as intended. Texas RE is concerned a reliability gap will occur if the two tests are not conducted simultaneously and in such a way the GO and TO can view the results of the test on the entire RAS.

Full Calendar Months

The SDT introduces a new term “full calendar months” that is neither defined in the Standard nor the NERC Glossary and is inconsistent with other Reliability Standards. Texas RE noticed a definition in the PRC-012-2 RSAW, but the definition should be in the NERC Glossary or within PRC-012-2 itself instead. Texas RE recommends the SDT provide the definition within the Standards process while considering other definitions already in place (such as “Calendar Year” in PRC-005-6).

Corrective Action Plan

As previously submitted on January 8, 2015, Texas RE recommends revising PRC-12-2 R7 to place at least minimal criteria around modifications to Corrective Action Plans (CAP) or corresponding CAP timetables. As currently drafted, PRC-12-2 R7 could be interpreted to permit RAS-entities to perpetually update their CAPs if “actions or timetables change” and then merely notify the RC of such changes. Texas RE recommends that the SDT consider some minimal criteria that RAS-entities must satisfy in order to update a CAP under PRC-12-2 R7.2. For instance, PRC-12-2 R7.2 could be revised to read: “Update the CAP for any reasonable changes in the required actions or implementation timetable.” In turn, PRC-12-2 R7.3 could be revised to read: “Notify each reviewing Reliability Coordinator and provide a reasoned justification for changes in CAP actions or timetables, and notify each reviewing Reliability Coordinator when the CAP is completed."

Feedback Mechanism

Texas RE noticed there is no feedback mechanism in the current standard for PCs to incorporate RC approved RAS modifications in subsequent planning processes. Texas RE understands this might not appropriate for the scope of this project, but requests the SDT to consider this issue in future reviews of applicable standards.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

The drafting team disagrees with your premise that the limited impact designation creates a reliability gap. As the drafting team has previously stated, we included the limited impact recognition in the standard to capture the intent of the RAS classification as suggested in the SPCS-SAMS report. The limited impact designation is intended to recognize that RAS vary in complexity and impact on the BES. All RAS (limited impact and others) must be considered in TPL assessments.

The drafting team developed the following to explain the relationship between TPL-001-4 and PRC-012-2.

1. All RAS (limited impact and non-limited impact) must be considered in TPL assessments. **<u>In no instance does the limited impact designation exempt a RAS from satisfying TPL-001-4 requirements.</u>** As far as TPL assessments are concerned, all RAS are assumed to operate correctly and the possible incorrect operation of RAS are not addressed by TPL-001-4. PRC-012-2 addresses this issue as described in #3 below.

2. Adherence to the TPL performance requirements is presupposed by PRC-012-2. PRC-012-2 further assures RAS compliance to TPL performance requirements (where applicable to planning events) by documenting the design and performance of the RAS through Attachment 1, Section II, item 3. The RC will verify that RAS actions satisfy performance objectives for the scope of events and conditions that the RAS is intended to mitigate according to the complementary portion of Attachment 2, Section I, item 1.

3. PRC-012-2 requires RAS to meet design and implementation requirements in addition to any applicable TPL-001-4 performance requirements. These design and implementation requirements pertain to inadvertent operation and failure to operate, and are included in the information required by Attachment 1, Section II, item 6 and Section III, item 4. The complementary portion of Attachment 2 used by the RC during the RAS review is Section I, items 5 and 7 and Section II, item 2.

4. RAS vary widely in their complexity and impact on the reliability of the BES. For RAS on the low end of the BES impact range, the standard allows for exemptions on the design and implementation requirements that are more appropriate for high-impact RAS. These exemptions are permitted only for these low impact (i.e., limited impact) RAS. As stated in the Supplemental Material section of the draft standard, requiring RAS with minimal impact to the BES to satisfy the single component failure and single component malfunction tests would add complexity to the RAS design and implementation with minimal benefit to BES reliability.

5. The RAS-entity provides justification for any RAS proposed as limited impact via Attachment 1, Section II, item 5. The RC will use the complementary portion of Attachment 2, Section I, item 6 to verify the RAS qualifies for limited impact designation.

6. The RC is responsible for reviewing all of the Attachment 1 information, including studies regarding any proposed new or functionally modified RAS. The RC is the functional entity best suited to perform the RAS review and make the limited impact designation because it has the widest area operational and reliability perspective of all functional entities and an awareness of reliability issues in any neighboring RC Area. A RAS designated by the RC as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. If the RAS is not deemed to be limited impact, then the additional documentation associated with a RAS single component malfunction (Attachment 1, Section II, item 6) and a RAS single component failure (Attachment 1, Section III, item 4) is required.

7. PRC-012-2, Requirement R4 mandates that all RAS will be periodically evaluated to verify the continued effectiveness and coordination of the RAS, as well as to verify that, if a RAS single component malfunction or single component failure were to occur, the requirements for BES performance would continue to be satisfied. A periodic evaluation is required because changes in system topology or operating conditions may change the effectiveness of a RAS or the way it impacts the BES. Requirement R4, Part 4.1.3 requires that limited impact RAS be evaluated for the inadvertent operation of the RAS or the failure of the RAS to operate to ensure that the RAS still warrants the limited impact designation. If the RAS is not deemed to be limited impact, then the additional evaluations associated with RAS single component malfunction (Requirement R4, Part 4.1.4) and a RAS single component failure (Requirement R4, Part 4.1.5) are required.

TPL-001-4: It is correct to state that TPL-001-4 does not distinguish between limited impact and other RAS. The actions of both types of RAS must be taken into account in the evaluation of Contingency events on the System in the System assessment required by TPL-001-4. The System performance requirements in TPL-001-4 must be met considering the actions of both types of RAS. The intent of Requirement R4, Part 4.1.5 is to verify that a single component failure in a RAS, other than limited impact 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 is designed. This analysis is needed to ensure that changing System conditions do not result in the single component failure requirement not being met. Requirement R4, Part 4.1.5 exempts the PC from evaluating limited impact RAS with regards to single component failure. The drafting team declines to make the suggested change.

Degraded RAS: The drafting team reiterates that the RC will be notified of degraded RAS. Please see the Mapping Document for Project 2007-06.2 Phase 2 of System Protection Coordination for Requirement R6 of PRC-001-1.1(ii) which logically maps out how the reliability objective of Requirement R6 is accomplished by requirements in other Reliability Standards.

Misoperations: The drafting team agrees that the definition of Misoperations for Protection Systems does not and should not include references to RAS because RAS are not Protection Systems. The drafting team constructed Requirement R5 such that all RAS operations, partial operations, and failure of RAS to operate when expected must be analyzed. The drafting team contends that Requirement R5 is clear and unambiguous as-written without a formal definition of a RAS misoperation being developed. NERC and the Regional Entities can request information at any time using a Section 1600 Data Request, so the addition of another requirement in PRC-012-2 is not necessary.

Functional Testing – R8: The standard requirements do not specify compliance methods, only the reliability objective(s). Requirement R8 mandates the overall RAS performance be verified, not that an overall test be conducted. Functional testing may be accomplished with end-to-end testing or a segmented approach. For segmented testing, each segment of a RAS must be tested. Overlapping segments can be tested individually negating the need for complex maintenance schedules and outages. When a RAS has more than one owner, each RAS-entity is obligated to participate in the various activities identified by the requirements to the extent of its ownership. Collaboration, coordination, and communication between and among entities regarding RAS issues helps to ensure efforts are not duplicated and best serves reliability by promoting awareness. For purposes of creating efficiencies, the drafting team maintains registered entities that currently share ownership of a RAS (RAS-entities) are in some manner already communicating, sharing information, and coordinating RAS tasks such as operations analysis, Corrective Action Plan (CAP) development, and functional testing. The drafting team is confident that entities will continue to do this after this standard is effective and that entities will communicate with each other if there is any question or doubt of responsibility surrounding any requirement. Because Requirement R8 mandates that RAS-entities verify the overall RAS performance and the proper operation of non-Protection System components, overlapping segment testing is required if segment testing is utilized rather than end-to-end testing. Your example appears to neglect the use of overlapping segment testing.

Full Calendar Months: The drafting team does not consider “full” to be a definitional term, rather a clarifying term used with a time interval. The drafting team uses the clarifier ‘full’ to be clear that partial time increments are not counted. For example, for four calendar months, if the starting point is in the middle of a calendar month (October 15), four full calendar months would begin November 1 and continue through February 28 (the last day of the month of the stated period).

Corrective Action Plan: As discussed in the Rational for Requirement R6 and R7, the implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. The A RAS deficiency may require the RC to impose operating restrictions so the System can operate in a reliable way until the CAP is completed. The drafting team contends that the probable operating restrictions will incent the RAS-entity to complete the CAP as quickly as possible. It is conceivable that an entity may have a “reasoned” justification to defer the end of a CAP; but as the drafting team just stated, there should be no reliability implications associated with the delay.

Feedback Mechanism: RAS modifications approved by the RC should be captured in subsequent PC planning processes in the same way as any other future planned reinforcement projects. The owner of the RAS would be expected to provide applicable steady-state, dynamic, and short circuit modeling data to its TP and PC according to the data requirements and reporting procedures developed per MOD-032-1, and a PC would incorporate this information into its planning models per TPL-001-4 Requirement R1, Part 1.1.3.

2. Implementation Plan for PRC-012-2: The drafting team revised the Implementation Plan to provide for the initial consideration of limited impact RAS, and to clarify that the initial obligation under Requirement R9 for a Reliability Coordinator that does not have a RAS database is to establish a RAS database by the effective date of PRC-012-2. Do you agree with the revised Implementation Plan? If no, please provide the basis for your disagreement and an alternate proposal.

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	No

Comment

In light of the above comments, HQT is of the view that the maximum allowable interval between functional tests should be twelve full calendar years for RAS that are not designated as limited impact RAS.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

The reliability objective of Requirement R8 is to maintain the non-Protection System components of a RAS; i.e., the controllers (programmable logic controllers (PLCs), personal computers (PCs), multi-function programmable relays, remote terminal units (RTUs), and logic processors), and to verify the overall performance of the RAS through functional testing. Functional tests validate RAS operation by ensuring System states are detected and processed, and that actions taken by the controls are correct and occur within the expected time using the in-service settings and logic (functional testing by default operates the processing logic and infrastructure of a RAS). Functional testing should not be confused with the component focused maintenance of PRC-005 Protection System Maintenance. PRC-005 is not applicable to non-Protection System components such as RAS controllers. RAS designated as limited impact have functional testing intervals of up to twelve full calendar years. However, all other RAS have up to six full calendar year intervals because of the higher risk they pose to negatively impact BES reliability should they operate incorrectly or fail to operate. The drafting team recognizes that PRC-005 extends the maintenance interval for monitored multifunction programmable relays to twelve calendar years; however, the drafting team asserts that the inadvertent operation or failure of a RAS subject to the six year functional test interval poses too much risk to the reliability of the BES to extend the test interval beyond six years.

Douglas Webb on Behalf of Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co. - 3, 6, 5, 1	
Answer	No
Comment	
In consideration of our comments relating to the term "limited impact," we are unable to support the Implementation Plan. The alternative proposal is incorporate into the Implementation Plan a future defined NERC Glossary term for "limited impact."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The drafting team maintains the description of limited impact is sufficient and declines to make the suggested change to the Implementation Plan.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Comment	
ERCOT signs on to the IRC SRC comments for Question 2. The SRC comments are as follows: The rationale for R2 states that RC review "minimizes the possibility of a conflict of interest that could exist because of business relationships among …." This explanatory purpose for R2 is not needed and in fact could prove untrue as not all RCs are independent from TOs, GOs, etc. The R3 rationale inserts the idea of "lack of dependability". This can be understood differently by different parties. For a hardware supplier, it can mean the equipment or technology is unreliable. And if taken to an extreme, this seems to open the path to requiring the RC to decide which generators should run based on the individual generators' forced outage rate (dependability rate?). We suggest this phrase be stricken from the R3 explanatory.	

For R4 the limited impact designation explanation, please clarify whether the reference to regions is meant to be an example of how the SDT came to its decision for R4 or whether it is a reference of the authority of what regions can do. We believe it is the former and the language should be improved.

The concept of 4.1.2 to “avoid adverse interactions” would seem to need some criteria for evaluating what “avoid” means. Rather than state “avoid”, we suggest this requirement to be rewritten to state: “The RAS does not adversely impact the performance of other RAS, and protection and control systems.”

· 4.1.4.4. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. Some Planners don’t use voltage deviation criteria. This should it not be rewritten to state “BES voltages shall be within the Planning Coordinator’s voltage criteria under pre and post contingency conditions”.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

The Rationale for Requirement R2 states that the RC review “minimizes” the possibility of a conflict of interest; it does not say that it “eliminates” the possibility. The drafting team maintains that the RC is the functional entity best suited to perform the RAS review because it has the widest area perspective of all functional entities and minimizes the possibility of a conflict of interest that could exist because of business relationships among the RAS-entity, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS.

The phrase “lack of dependability” in the Rationale for Requirement R3 is an example of one of the possible reliability issues with the RAS that the RC review is intended to discover.

WECC and NPCC were cited because those are the only two Regions that classified RAS based upon certain criteria. The SPCS-SAMS team also recognized these Regional classifications and made similar albeit different recommendations. The drafting team considered the attributes of each of these regional classifications in creating the guidance for limited impact designation. The limited impact designation is applicable on a continent-wide basis via NERC Reliability Standard PRC-012-2. Based on your comment, the drafting team modified the language in the Rationale box.

The drafting team maintains that the current language “avoids adverse interactions” is clear and that the suggested language does not provide additional clarity.

Requirement R5 of TPL-001-4 requires PC’s and TP’s to have criteria for post contingency voltage deviations.

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Comment	

Implementation Plan

Texas RE recommends reducing the implementation period. This is a series of processes that already exist in some form or fashion and should not require a new construct that would take three years. In Requirement R9, the SDT indicates requirements follow “industry practice” which is a twelve month periodicity. Does the SDT contend that there are RASes in place that an RC or PC does not know about?

Texas RE recommends that the SDT *eliminate the proposed implementation period or at least shorten the proposed three-year implementation period for PRC-12-2 to six months*. Alternatively, the SDT should link the 60-full-calendar month (currently revised to “5 full calendar years”) compliance window in PRC-12-2, R4 and the six- and twelve-year compliance periods in PRC-12-2, R8 to the effective date of PRC-12-2 and not the extended date (if any) set forth in the proposed implementation plan.

The proposed PRC-12-2 establishes a process for reviewing new, functionally modified, or retiring RAS. As the SDT has recognized, failing to implement such a RAS review process could result in a significant gap in reliability. Specifically, the SDT stated in the rationale for Requirement R1 that RAS “action(s) can have a *significant impact on the reliability and integrity of the Bulk Electric System (BES)*.” Given the importance of the RAS review scheme for reliability, Texas RE believes that three years is too long to implement the process contemplated in the proposed PRC-12-2.

Review Process Timeline

Texas RE also believes that the nature of the review process itself also counsels in favor of a shorter review period. For example, PRC-12-2, R1 – R3 establishes the basic framework for RAS review. These requirements mandate that RAS-entities provide certain information regarding RAS to their respective Reliability Coordinators (RC), a minimum four full calendar month period for the RC to review this information, and then a subsequent obligation for the RAS-entity to resolve any reliability issues identified by the RC prior to installing, functionally modifying, or retiring a particular RAS. Accordingly, these requirements do not contemplate immediate changes to existing physical assets, significant internal process transformations, or other issues that could potentially justify a three-year implementation period. Rather, they largely focus solely on the exchange and review of documentation, such as one-line drawings, for each RAS that is likely already be in the RAS-entity's possession today. RAS-entities and their associated RCs should therefore be able to begin the RAS review process with only minimal lead time following the adoption of PRC-12-2. Texas RE would further note that although RCs may need additional compliance resources to perform the RAS reviews contemplated under PRC-12-2, the existing language in PRC-12-2, R2 already provides RCs and RAS-entities with the flexibility to extend the review period if necessary based on a "mutually agreed upon schedule."

A similar rationale applies to the misoperation review and correction process in PRC-12-2, R5. As the SDT notes, "[t]he correct operation of a RAS is important for maintaining the reliability and integrity of the BES. *Any incorrect operation of a RAS indicates that the RAS effectiveness and/or coordination has been compromised.*" Texas RE agrees with this statement. In light of this fact, however, Texas RE believes that RAS-entities should begin RAS operational performance assessments following a RAS failure or misoperation immediately upon adoption of PRC-12-2 in order to avoid a significant reliability gap.

If the SDT elects to retain an implementation period of any length, Texas RE recommends that such implementation plan not apply to PRC-12-2, R4 and R8. These requirements already have significant time periods for RAS-entities to complete their compliance obligations embedded within them. For example, RAS-entities have six years under PRC-12-2, R8 to complete initial functional tests of their RAS (and 12 years for limited impact RAS if that definition is retained). Given that PRC-12-2, R4 and R8 already provide extended compliance horizons, Texas RE does not believe that additional time is necessary to implement these requirements. Instead, the 6-full-calendar month period in PRC-12-2, R4 and the six- and twelve-year periods in PRC-12-2, R8 should begin on the effective date of PRC-12-2 itself.

Additionally, the Implementation Plan contains the same "limited impact" language Texas RE has concerns about.

Texas RE requests the SDT provide justification for the testing timelines.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

Review Process Timeline
The notion that entities could use the “mutually agreed upon schedule” clause in the Standard assumes that all entities are already able to meet all the requirements of the Standard. The drafting team is unable to make this assertion and expects that many functional entities will need to establish new frameworks which could include the hiring and training of personnel to ensure the requirements of Reliability Standard PRC-012-2 are met. The drafting team asserts that the 36 month implementation period is reasonable and appropriate.

Entities are encouraged to begin work prior to the effective date of the Standard. For example, an entity may choose to work with their RC prior to the effective date of the Standard to submit the information to determine that a RAS is limited impact prior to implementation, but that designation does not become relevant until the effective date of PRC-012-2.

The existing NERC PRC-016-1 Remedial Action Scheme Misoperations will not be retired until the effective date 36 months after PRC-012-2 is approved by the appropriate authority. Therefore, the drafting team contends that no reliability gap will exist.

The effective date of the Standard is the first day of the first calendar quarter that is thirty six (36) months after the effective date of the applicable governmental authority’s order approving the standard. The drafting team declines to make the suggested change because the drafting team feels that the implementation period, as drafted, provides a necessary period for preparation for compliance and because this time period is consistent with the implementation period for the rest of the standard.

The Reliability Coordinator has responsibility for reliability of operations within its Reliability Coordinator Area and has discretion to designate a RAS as limited impact on a case-by-case basis. The drafting team has determined that the general description of limited impact RAS, which only describes actions to which a RAS cannot cause or contribute and be considered limited impact, does not rise to the level of a NERC Glossary definition. Rather, the explanation of a limited impact RAS is only high level guidance that must be considered by an RC when using its discretion and its wide area perspective to determine whether a limited impact designation is necessary for a given RAS.

The drafting team reviewed PRC-005-6 and selected the functional testing interval in an attempt to build synergy between the two Standards. The drafting team believes the same maintenance and testing groups will participate in the component testing of PRC-005-6 and the functional testing of PRC-012-2. The drafting team understands that PRC-005-6 provides variable maintenance intervals to up to twelve calendar years for multifunction programmable relays dependent on monitoring; however, the drafting team asserts that the inadvertent operation or failure of a RAS subject to the six year functional test interval poses too much risk to the reliability of the BES to

extend the test interval beyond six years (12 years for RAS determined to have a limited impact) regardless of the monitoring in place. The drafting team attempted to balance the reliability interest of frequent functional testing with the resources required to perform that testing, which can be significant, and believes that six years is a reasonable compromise.	
Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Comment	
There was no general comment section provided this round, so TVA is providing the following comments to support our negative votes on the ballot: TVA continues to believe that the responsibility for reviewing and approving new or functionally modified RAS schemes belongs with the Planning Coordinator and not the Reliability Coordinator. Oversight of the planning of the Bulk Electric System or the entities responsible for Bulk Electric System planning belongs with the Planning Coordinator. From TVA's perspective, the proposed standard, as written, is in direct conflict with the Functional Model, and requires a compelling reason to justify the deviation. The facts that there are fewer Reliability Coordinators (as opposed to Planning Coordinators) and that the Reliability Coordinators have the "widest-area view" do not support a significant deviation from the Functional Model. Moreover, such analysis would beyond the normal Reliability Coordinator functions, the Reliability Coordinators would not have the expertise to conduct RAS analysis in the planning horizon. Simply put, Reliability Coordinators do not have trained personnel or the appropriate tools to complete a comprehensive assessment. Planning Coordinators have oversight over all other aspects of planning of the Bulk Electric System, and there is no reason to treat Remedial Action Schemes differently.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take	

precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009. The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. As the drafting team stated in the Rationale and Supplemental Material section of the standard, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.	
Ben Engelby - ACES Power Marketing - 6, Group Name ACES Standards Collaborators - PRC-012-2 Project	
Answer	Yes
Comment	
We agree with the SDT that the implementation plan is appropriate.	
Likes 0	
Dislikes 0	
Response	
William Temple on Behalf of Mark Holman, PJM Interconnection, L.L.C. - 2	
Answer	Yes
Comment	

PJM supports the comments submitted by the ISO/RTO Council.	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC-ISONE	
Answer	Yes
Comment	

The rationale for R2 states that RC review “minimizes the possibility of a conflict of interest that could exist because of business relationships among ….”. This explanatory purpose for R2 is not needed and in fact could prove untrue as not all RCs are independent from TOs, GOs, etc.

The R3 rationale inserts the idea of “lack of dependability”. This can be understood differently by different parties. For a hardware supplier, it can mean the equipment or technology is unreliable. And if taken to an extreme, this seems to open the path to requiring the RC to decide which generators should run based on the individual generators’ forced outage rate (dependability rate?). We suggest this phrase be stricken from the R3 explanatory.

For R4 the limited impact designation explanation, please clarify whether the reference to regions is meant to be an example of how the SDT came to its decision for R4 or whether it is a reference of the authority of what regions can do. We believe it is the former and the language should be improved.

The concept of 4.1.2 to “avoid adverse interactions” would seem to need some criteria for evaluating what “avoid” means. Rather than state “avoid”, we suggest this requirement to be rewritten to state: “The RAS does not adversely impact the performance of other RAS, and protection and control systems.”

4.1.4.4. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. Some Planners don't use voltage deviation criteria. This should it not be rewritten to state "BES voltages shall be within the Planning Coordinator's voltage criteria under pre and post contingency conditions".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The Rationale for Requirement R2 states that the RC review "minimizes" the possibility of a conflict of interest; it does not say that it "eliminates" the possibility. While it is true that not all RCs are independent from RAS-entities, RCs are more likely to be independent from RAS-entities than other functional model entities that would be more likely to be involved with the planning or implementation of a RAS. The phrase "lack of dependability" in the Rationale for Requirement R3 is referring only to the RAS. This is just an example of one of the possible reliability issues with the RAS that the RC review is intended to uncover. WECC and NPCC were cited because those are the only two Regions that classified RAS based upon certain criteria. The SPCS-SAMS team also recognized these Regional classifications and made similar albeit different recommendations. The drafting team considered the attributes of each of these regional classifications in creating the guidance for limited impact designation. The limited impact designation is applicable on a continent-wide basis via NERC Reliability Standard PRC-012-2. Based on your comment, the drafting team modified the language in the Rationale for Requirement R4. The drafting team maintains that the current language "avoids adverse interactions" is clear and declines to make the suggested change. The drafting team worded Requirement R4, Part 4.1.4 to reflect Requirement R5 of TPL-001-4 which requires PCs and TPs to have criteria for post contingency voltage deviations.	
Larry Heckert on Behalf of Kenneth Goldsmith, Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes

Comment	
Alliant Energy supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC No HQ and Dominion	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3	

Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Oshani Pathirane on Behalf of Payam Farahbakhsh, Hydro One Networks, Inc. - 1, 3	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	

Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	

Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Jared Shakespeare - Peak Reliability - 1	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Erika Doot - U.S. Bureau of Reclamation - 5	

Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin on Behalf of Michael Moltane, International Transmission Company Holdings Corporation - 1	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson on Behalf of Michael Puscas, ISO New England, Inc. - 2	

Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Czyz - Oglethorpe Power Corporation - 5	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis on Behalf of Jason Snodgrass, Georgia Transmission Corporation - 1	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Christy Koncz - Public Service Enterprise Group - 1,3,5,6 - NPCC,RF, Group Name PSEG	

Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	

Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Randi Heise - Dominion - Dominion Resources, Inc. - 5, Group Name Dominion - RCS	

Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan on Behalf of Rod Kinard, Oncor Electric Delivery - 1	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Michael DeLoach - AEP - 3	

Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Michael DeLoach - AEP - 3	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - City and County of San Francisco - 5	

Answer	Yes
Comment	
Likes 0	
Dislikes 0	
Response	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

Draft 3 of PRC-012-2 corrects the applicability of the fill-in-the-blank standards (PRC-012-1, PRC-013-1, and PRC-014-1) by assigning the requirement responsibilities to the specific users, owners, and operators of the Bulk-Power System, and incorporates the reliability objectives of all the RAS-related standards. This draft contains nine requirements and measures, the associated rationale boxes and corresponding technical guidelines. There are also three attachments within the draft standard that are incorporated via references in the requirements. This draft of PRC-012-2 is posted for a 10-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	February 12, 2014
SAR posted for comment	February 18, 2014
Standards Committee approved the SAR	June 10, 2014
Draft 1 of PRC-012-2 posted for informal comment	April 30 – May 20, 2015
Draft 1 of PRC-012-2 posted for 45-day formal comment period with initial ballot	August 20 – October 5, 2015
Draft 2 of PRC-012-2 posted for 45-day formal comment period with additional ballot	November 25, 2015 – January 8, 2016
Draft 3 of PRC-012-2 posted for 45-day formal comment period with additional ballot	February 3, 2016 – March 18, 2016
Draft 3 of PRC-012-2 posted for 10-day final ballot.	April 20 – 29, 2016

Anticipated Actions	Date
Adoption by Board of Trustees	May 2016

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Remedial Action Schemes
2. **Number:** PRC-012-2
3. **Purpose:** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).
4. **Applicability:**
    - **4.1. Functional Entities:**
        - **4.1.1.** Reliability Coordinator
        - **4.1.2.** Planning Coordinator
        - **4.1.3.** RAS-entity – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS
    - **4.2. Facilities:**
        - **4.2.1.** Remedial Action Schemes (RAS)
5. **Effective Date:** See the Implementation Plan for PRC-012-2.

B. Requirements and Measures

Rationale for Requirement R1: Each Remedial Action Scheme (RAS) is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES). Therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification or retirement; i.e., removal from service must be completed prior to implementation or retirement.

Functional modifications consist of any of the following:

- Changes to System conditions or Contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

To facilitate a review that promotes reliability, the RAS-entity must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity provide them to the reviewing Reliability Coordinator (RC). The RC (reviewing RC) that coordinates the area where the RAS is located is responsible for the review. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate and submit a single, coordinated Attachment 1 to the reviewing RC. In cases where a RAS crosses RC Area boundaries, each affected RC is responsible for conducting either individual reviews or participating in a coordinated review.

R1. Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, a copy of the Attachment 1 documentation and the dated communications with the reviewing Reliability Coordinator(s) in accordance with Requirement R1.

Rationale for Requirement R2: The RC is the functional entity best suited to perform the RAS review because it has the widest area operational and reliability perspective of all functional entities and an awareness of reliability issues in any neighboring RC Area. This Wide Area purview facilitates the evaluation of interactions among separate RAS as well as interactions among RAS and other protection and control systems. Review by the RC also minimizes the possibility of a conflict of interest that could exist because of business relationships among the RAS-entity, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC is not expected to possess more information or ability than anticipated by their

functional registration as designated by NERC. The RC may request assistance to perform RAS reviews from other parties such as the PC or regional technical groups; however, the RC will retain the responsibility for compliance with this requirement.

Attachment 2 of this standard is a checklist the RC can use to identify design and implementation aspects of RAS and facilitate consistent reviews for each submitted RAS. The time frame of four full calendar months is consistent with current utility and regional practice; however, flexibility is provided by allowing the RC(s) and RAS-entity(ies) to negotiate a mutually agreed upon schedule for the review.

Note: An RC may need to include this task in its reliability plan(s) for the NERC Regions(s) in which it is located.

R2. Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated reports, checklists, or other documentation detailing the RAS review, and the dated communications with the RAS-entity in accordance with Requirement R2.

Rationale for Requirement R3: The RC review is intended to identify reliability issues that must be resolved before the RAS can be put in service. Examples of reliability issues include a lack of dependability, security, or coordination.

A specific time period for the RAS-entity to respond to the reviewing RC following identification of any reliability issue(s) is not necessary because the RAS-entity wants to expedite the timely approval and subsequent implementation of the RAS.

A specific time period for the RC to respond to the RAS-entity following the RAS review is also not necessary because the RC will be aware of (1) any reliability issues associated with the RAS not being in service and (2) the RAS-entity's schedule to implement the RAS to address those reliability issues. Since the RC is the ultimate arbiter of BES operating reliability, resolving reliability issues is a priority for the RC and serves as an incentive to expeditiously respond to the RAS-entity.

R3. Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Acceptable evidence may include, but is not limited to, dated documentation and communications with the reviewing Reliability Coordinator that no reliability issues

were identified during the review or that all identified reliability issues were resolved in accordance with Requirement R3.

Rationale for Requirement R4: Requirement R4 mandates that an evaluation of each RAS be performed at least once every five full calendar years. The purpose of the periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that, if a RAS single component malfunction or single component failure were to occur, the requirements for BES performance would continue to be satisfied. A periodic evaluation is required because changes in System topology or operating conditions may change the effectiveness of a RAS or the way it impacts the BES.

RAS are unique and customized assemblages of protection and control equipment that vary in complexity and impact on the reliability of the BES. In recognition of these differences, RAS can be designated by the reviewing RC(s) as limited impact. A limited impact RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. The "BES" qualifier in the preceding statement modifies all of the conditions that follow it. Limited impact RAS are not subject to the RAS single component malfunction and failure tests of Parts 4.1.4 and 4.1.5, respectively. Requiring a limited impact RAS to meet these tests would add complexity to the design with minimal benefit to BES reliability. See the Supplemental Material for more on the limited impact designation.

The standard recognizes the Local Area Protection Scheme (LAPS) classification in WECC (Western Electricity Coordinating Council) and the Type III classification in NPCC (Northeast Power Coordinating Council) as initially appropriate for limited impact designation. A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type III in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.

For existing RAS, the initial performance of Requirement R4 must be completed within five full calendar years of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within five full calendar years of the RAS approval date by the reviewing RC(s). Five full calendar years was selected as the maximum time frame between evaluations based on the time frames for similar requirements in Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation can be performed sooner if it is determined that material changes to System topology or System operating conditions could potentially impact the effectiveness or coordination of the RAS. System changes also have the potential to alter the reliability impact of limited impact RAS on the BES. Requirement 4, Part 4.1.3 explicitly requires the periodic evaluation of limited impact RAS to verify the limited impact designation remains applicable; the PC can use its discretion as to how this evaluation is performed. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluations (Requirement R4, Parts 4.1.1 through 4.1.5) are planning analyses that may involve modeling of the interconnected transmission system to assess BES performance. The Planning Coordinator (PC) is the functional entity best suited to perform this evaluation because they have a wide area planning perspective. To promote reliability, the PC is required to provide the results of the evaluation to each impacted Transmission Planner and Planning Coordinator, in addition to each reviewing RC and RAS-entity. In cases where a RAS crosses PC boundaries, each affected PC is responsible for conducting either individual evaluations or participating in a coordinated evaluation.

The previous version of this standard (PRC-012-1 Requirement 1, R1.4) states "… 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." Requirement R4 clarifies that the inadvertent operation to be considered would only be that caused by the malfunction of a single RAS component. This allows security features to be designed into the RAS such that inadvertent operation due to a single component malfunction is prevented. Otherwise, consistent with PRC-012-1 Requirement 1, R1.4, the RAS should be designed so that its whole or partial inadvertent operation due to a single component malfunction satisfies the System 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 some other Contingency or System condition not defined in TPL-001-4 (therefore without performance requirements), its inadvertent operation still must meet some minimum System performance requirements. However, instead of referring to the TPL-001-4, Requirement R4 lists the System performance requirements that the inadvertent operation must satisfy. The performance requirements listed (Parts 4.1.4.1 – 4.1.4.5) are the ones that are common to all planning events P0-P7 listed in TPL-001-4.

R4. Each Planning Coordinator, at least once every five full calendar years, shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Perform an evaluation of each RAS within its planning area to determine whether:

4.1.1. The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed.

4.1.2. The RAS avoids adverse interactions with other RAS, and protection and control systems.

4.1.3. For limited impact[1] RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

4.1.4. Except for limited impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following:

4.1.4.1. The BES shall remain stable.

4.1.4.2. Cascading shall not occur.

4.1.4.3. Applicable Facility Ratings shall not be exceeded.

4.1.4.4. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

4.1.4.5. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

4.1.5. Except for limited impact RAS, 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 is designed.

4.2. Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.

M4. Acceptable evidence may include, but is not limited to, dated reports or other documentation of the analyses comprising the evaluation(s) of each RAS and dated communications with the RAS-entity(ies), Transmission Planner(s), Planning Coordinator(s), and the reviewing Reliability Coordinator(s) in accordance with Requirement R4.

[1] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

Rationale for Requirement R5: The correct operation of a RAS is important for maintaining the reliability and integrity of the BES. Any incorrect operation of a RAS indicates that the RAS effectiveness and/or coordination has been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: 1) verify RAS operation was consistent with the implemented design; or 2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120 full calendar day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation. To promote reliability, each RAS-entity is required to provide the results of RAS operational performance analyses that identified any deficiencies to its reviewing RC(s).

RAS-entities may need to collaborate with their associated Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation was triggered correctly (Part 5.1.1), responded as designed (Part 5.1.2), and that the resulting BES response (Parts 5.1.3 and 5.1.4) was consistent with the intended functionality and design of the RAS. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to conduct and submit a single, coordinated operational performance analysis.

R5. Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Participate in analyzing the RAS operational performance to determine whether:

5.1.1. The System events and/or conditions appropriately triggered the RAS.

5.1.2. The RAS responded as designed.

5.1.3. The RAS was effective in mitigating BES performance issues it was designed to address.

5.1.4. The RAS operation resulted in any unintended or adverse BES response.

5.2. Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).

M5. Acceptable evidence may include, but is not limited to, dated documentation detailing the results of the RAS operational performance analysis and dated communications with participating RAS-entities and the reviewing Reliability Coordinator(s) in accordance with Requirement R5.

Rationale for Requirement R6: Deficiencies identified in the periodic RAS evaluation conducted by the PC pursuant to Requirement R4, in the operational performance analysis conducted by the RAS-entity pursuant to Requirement R5, or in the functional test performed by the RAS-entity pursuant to Requirement R8, potentially pose a reliability risk to the BES. To mitigate these potential reliability risks, Requirement R6 mandates that each RAS-entity develop a Corrective Action Plan (CAP) to address the identified deficiency. The CAP contains the mitigation actions and associated timetable necessary to remedy the specific deficiency. The RAS-entity may request assistance with CAP development from other parties such as its Transmission Planner or Planning Coordinator; however, the RAS-entity has the responsibility for compliance with this requirement.

If the CAP requires that a functional change be made to a RAS, the RAS-entity will need to submit information identified in Attachment 1 to the reviewing RC(s) prior to placing RAS modifications in service per Requirement R1.

Depending on the complexity of the identified deficiency(ies), development of a CAP may require studies, and other engineering or consulting work. A maximum time frame of six full calendar months is specified for RAS-entity collaboration on the CAP development. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to develop and submit a single, coordinated CAP.

R6. Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

- Being notified of a deficiency in its RAS pursuant to Requirement R4, or
- Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or
- Identifying a deficiency in its RAS pursuant to Requirement R8.

M6. Acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each reviewing Reliability Coordinator and each RAS-entity in accordance with Requirement R6.

Rationale for Requirement R7: Requirement R7 mandates each RAS-entity implement a CAP (developed in Requirement R6) that mitigates the deficiencies identified in Requirements R4, R5, or R8. By definition, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem." The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. Each reviewing Reliability Coordinator must be notified if CAP actions or timetables change, and when the CAP is completed.

R7. Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

7.1. Implement the CAP.

7.2. Update the CAP if actions or timetables change.

7.3. Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

M7. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, and communication with the reviewing Reliability Coordinator(s) that documents the implementation, updating, or completion of a CAP in accordance with Requirement R7.

Rationale for Requirement R8: Due to the wide variety of RAS designs and implementations, and the potential for impacting BES reliability, it is important that periodic functional testing of a RAS be performed. A functional test provides an overall confirmation of the RAS to operate as designed and verifies the proper operation of the non-Protection System (control) components of a RAS that are not addressed in PRC-005. Protection System components that are part of a RAS are maintained in accordance with PRC-005.

The six or twelve full calendar year test interval, which begins on the effective date of the standard pursuant to the PRC-012-2 implementation plan, is a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS. Extending to longer intervals increases the reliability risk to the BES posed by an undiscovered latent failure that could cause an incorrect operation or failure of the RAS. The RAS-entity is in the best position to determine the testing procedure and schedule due to its overall knowledge of the RAS design, installation, and functionality. Functional testing may be accomplished with end-to-end testing or a segmented approach. For segmented testing, each segment of a RAS must be tested. Overlapping segments can be tested individually negating the need for complex maintenance schedules and outages.

The maximum allowable interval between functional tests is six full calendar years for RAS that are not designated as limited impact RAS and twelve full calendar years for RAS that are designated as limited impact RAS. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. A correct operation of a RAS qualifies as a functional test for those RAS segments which operate (documentation for compliance with Requirement R5 Part 5.1). If an event causes a partial operation of a RAS, the segments without an operation will require a separate functional test within the maximum interval with the starting date determined by the previous successful test of the segments that did not operate.

R8. Each RAS-entity shall participate in performing a functional test of each of its RAS to verify the overall RAS performance and the proper operation of non-Protection System components: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

- At least once every six full calendar years for all RAS not designated as limited impact, or
- At least once every twelve full calendar years for all RAS designated as limited impact

M8. Acceptable evidence may include, but is not limited to, dated documentation detailing the RAS operational performance analysis for a correct RAS segment or an end-to-end operation (Measure M5 documentation), or dated documentation demonstrating that a functional test of each RAS segment or an end-to-end test was performed in accordance with Requirement R8.

Rationale for Requirement R9: The RAS database is a comprehensive record of all RAS existing in a Reliability Coordinator Area. The database enables the RC to provide other entities high-level information on existing RAS that could potentially impact the operational and/or planning activities of that entity. Attachment 3 lists the minimum information required for the RAS database, which includes a summary of the RAS initiating conditions, corrective actions, and System issues being mitigated. This information allows an entity to evaluate the reliability need for requesting more detailed information from the RAS-entities identified in the database contact information. The RC is the appropriate entity to maintain the database because the RC receives the required database information when a new or modified RAS is submitted for review. The twelve full calendar month time frame is aligned with industry practice and allows sufficient time for the RC to collect the appropriate information from RAS-entities and update the RAS database.

R9. Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once every twelve full calendar months. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M9. Acceptable evidence may include, but is not limited to, dated spreadsheets, database reports, or other documentation demonstrating a RAS database was updated in accordance with Requirement R9.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The RAS-entity (Transmission Owner, Generator Owner, and Distribution Provider) shall each keep data or evidence to show compliance with Requirements R1, R3, R5, R6, R7, and R8, and Measures M1, M3, M5, M6, M7, and M8 since the last audit, unless directed by its Compliance Enforcement

Authority to retain specific evidence for a longer period of time as part of an investigation.

The Reliability Coordinator shall each keep data or evidence to show compliance with Requirements R2 and R9, and Measures M2 and M9 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Planning Coordinator shall each keep data or evidence to show compliance with Requirement R4 and Measure M4 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a RAS-entity (Transmission Owner, Generator Owner or Distribution Provider), Reliability Coordinator, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The RAS-entity failed to provide the information identified in Attachment 1 to each Reliability Coordinator prior to placing a new or functionally modified RAS in service or retiring an existing RAS in accordance with Requirement R1.
R2.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90 full calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in accordance with Requirement R2.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	N/A	N/A	N/A	The RAS-entity failed to resolve identified reliability issue(s) to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in service or retiring an existing RAS in accordance with Requirement R3.
R4.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but was late by less than or equal to 30 full calendar days.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate one of the Parts 4.1.1 through 4.1.5.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but was late by more than 90 full calendar days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate two or more of the Parts 4.1.1 through 4.1.5. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to provide the results to one or more of the receiving entities listed in Part 4.2. OR The Planning Coordinator failed to perform the evaluation in accordance with Requirement R4.
R5.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by less than or equal to 10 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address one of the Parts 5.1.1 through 5.1.4.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address two or more of the Parts 5.1.1 through 5.1.4.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to provide the results (Part 5.2) to one or more of the reviewing Reliability Coordinator(s). OR The RAS-entity failed to perform the analysis in accordance with Requirement R5.
R6.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30 full calendar days. OR The RAS-entity developed a Corrective Action Plan but failed to submit it to one or

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				more of its reviewing Reliability Coordinator(s) in accordance with Requirement R6. OR The RAS-entity failed to develop a Corrective Action Plan in accordance with Requirement R6.
R7.	The RAS-entity implemented a CAP in accordance with Requirement R7, Part 7.1, but failed to update the CAP (Part 7.2) if actions or timetables changed, or failed to notify (Part 7.3) each of the reviewing Reliability Coordinator(s) of the updated CAP or completion of the CAP.	N/A	N/A	The RAS-entity failed to implement a CAP in accordance with Requirement R7, Part 7.1.
R8.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by less than	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 30 full calendar days	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 60 full calendar days	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 90 full calendar days.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	or equal to 30 full calendar days.	but less than or equal to 60 full calendar days.	but less than or equal to 90 full calendar days.	OR The RAS-entity failed to perform the functional test for a RAS as specified in Requirement R8.
R9.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90 full calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

D. Regional Variances

None.

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by the Board of Trustees	
0	March 16, 2007	Identified by Commission as "fill-in-the-blank" with no action taken on the standard	
1	November 13, 2014	Adopted by the Board of Trustees	
1	November 19, 2015	Accepted by Commission for informational purposes only	
2		Adopted by Board of Trustees	New

Attachment 1
Supporting Documentation for RAS Review

The following checklist identifies important Remedial Action Scheme (RAS) information for each new or functionally modified[2] RAS that the RAS-entity must document and provide to the reviewing Reliability Coordinator(s) (RC). If an item on this list does not apply to a specific RAS, a response of “Not Applicable” for that item is appropriate. When RAS are submitted for functional modification review and approval, only the proposed modifications to that RAS require review; however, the RAS-entity must provide a summary of the existing functionality. The RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS. Additional entities (without decision authority) may be part of the RAS review process at the request of the RC.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.
2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.
3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP.
4. Data to populate the RAS database:
    a. RAS name.
    b. Each RAS-entity and contact information.
    c. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
    d. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
    e. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
    f. Action(s) to be taken by the RAS.
    g. Identification of limited impact[3] RAS.
    h. Any additional explanation relevant to high-level understanding of the RAS.

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[2] Functionally modified: Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

[3] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

II. Functional Description and Transmission Planning Information

1. Contingencies and System conditions that the RAS is intended to remedy.
2. The action(s) to be taken by the RAS in response to disturbance conditions.
3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and the date those technical studies were performed.
4. Information regarding any future System plans that will impact the RAS.
5. RAS-entity proposal and justification for limited impact designation, if applicable.
6. Documentation describing the System performance resulting from the possible inadvertent operation of the RAS, except for limited impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be limited impact must satisfy all of the following:
   a. The BES shall remain stable.
   b. Cascading shall not occur.
   c. Applicable Facility Ratings shall not be exceeded.
   d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.
   e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.
7. An evaluation indicating that the RAS settings and operation avoid adverse interactions with other RAS, and protection and control systems.
8. Identification of other affected RCs.

III. Implementation

1. Documentation describing the applicable equipment used for detection, dc supply, communications, transfer trip, logic processing, control actions, and monitoring.
2. Information on detection logic and settings/parameters that control the operation of the RAS.
3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in service or is being maintained.
4. Documentation describing the System performance resulting from a single component failure in the RAS, except for limited impact RAS, when the RAS is intended to operate. A single component failure in a RAS not determined to be limited impact must 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 is designed. The documentation should describe or illustrate how the design achieves this objective.
5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies RAS information that the RAS-entity shall document and provide to each reviewing RC.

1. Information necessary to ensure that the RC is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of applicable technical studies and technical justifications upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

Attachment 2
Reliability Coordinator RAS Review Checklist

The following checklist identifies reliability-related considerations for the Reliability Coordinator (RC) to review and verify for each new or functionally modified[4] Remedial Action Scheme (RAS). The RC review is not limited to the checklist items and the RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS. If a checklist item is not relevant to a particular RAS, it should be noted as "Not Applicable." If reliability considerations are identified during the review, the considerations and the proposed resolutions should be documented with the remaining applicable Attachment 2 items.

I. Design

1. The RAS actions satisfy performance objectives for the scope of events and conditions that the RAS is intended to mitigate.
2. The designed timing of RAS operation(s) is appropriate to its BES performance objectives.
3. The RAS arming conditions, if applicable, are appropriate to its System performance objectives.
4. The RAS avoids adverse interactions with other RAS, and protection and control systems.
5. The effects of RAS incorrect operation, including inadvertent operation and failure to operate, have been identified.
6. Determination whether or not the RAS is limited impact.[5] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.
7. Except for limited impact RAS as determined by the RC, the possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following:
    a. The BES shall remain stable.
    b. Cascading shall not occur.
    c. Applicable Facility Ratings shall not be exceeded.

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[4] Functionally modified: Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

[5] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

   d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

   e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

8. The effects of future BES modifications on the design and operation of the RAS have been identified, where applicable.

II. Implementation

1. The implementation of RAS logic appropriately correlates desired actions (outputs) with events and conditions (inputs).
2. Except for limited impact RAS as determined by the RC, a single component failure in a RAS does not prevent the BES from meeting the same performance requirements as those required for the events and conditions for which the RAS is designed.
3. The RAS design facilitates periodic testing and maintenance.
4. The mechanism or procedure by which the RAS is armed is clearly described, and is appropriate for reliable arming and operation of the RAS for the conditions and events for which it is designed to operate.

III. RAS Retirement

RAS retirement reviews should assure that there is adequate justification for why a RAS is no longer needed.

Attachment 3
Database Information

1. RAS name.
2. Each RAS-entity and contact information.
3. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
5. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
6. Action(s) to be taken by the RAS.
7. Identification of limited impact[6] RAS.
8. Any additional explanation relevant to high-level understanding of the RAS.

[6] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

Technical Justification

4.1.1 Reliability Coordinator

The Reliability Coordinator (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. The Wide Area purview 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, Planning Coordinator, Transmission Planner, or other entities 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.

4.1.2 Planning Coordinator

The Planning Coordinator (PC) is the best-suited functional entity to perform the RAS evaluation 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, similar to the planning analyses performed by PCs.

4.1.3 RAS-entity

The RAS-entity is any Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If all of the RAS (RAS components) have a single owner, then that RAS-entity has sole responsibility for all the activities assigned within the standard to the RAS-entity. If the RAS (RAS components) have more than one owner, then each separate RAS component owner is a RAS-entity and is obligated to participate in various activities identified by the Requirements.

The standard does not stipulate particular compliance methods. RAS-entities have the option of collaborating to fulfill their responsibilities for each applicable requirement. Such collaboration and coordination may promote efficiency in achieving the reliability objectives of the requirements; however, the individual RAS-entity must be able to demonstrate its participation for compliance. As an example, the individual RAS-entities could collaborate to produce and submit a single, coordinated Attachment 1 to the reviewing RC pursuant to Requirement R1 to initiate the RAS review process.

Limited impact

RAS are unique and customized assemblages of protection and control equipment that vary in complexity and impact on the reliability of the BES. These differences in RAS design, action, and risk to the BES are identified and verified within the construct of Requirements R1-R4 of PRC-012-2.

The reviewing RC has the authority to designate a RAS as limited impact if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. The reviewing RC makes the final determination as to whether a RAS qualifies for the limited impact designation based upon the studies and other information provided with the Attachment 1 submittal by the RAS-entity.

The standard recognizes the Local Area Protection Scheme (LAPS) classification in WECC (Western Electricity Coordinating Council) and the Type III classification in NPCC (Northeast Power Coordinating Council) as initially appropriate for limited impact designation. The following information describing the aforementioned WECC and NPCC RAS is excerpted from the respective regional documentation[7].The drafting team notes that the information below represents the state of the WECC and NPCC regional processes at the time of this standard development and is subject to change before the effective date of PRC-012-2.

WECC: Local Area Protection Scheme (LAPS)

A Remedial Action Scheme (RAS) whose failure to operate would NOT result in any of the following:

- Violations of TPL-001-WECC-RBP System Performance RBP,
- Maximum load loss ≥ 300 MW,
- Maximum generation loss ≥ 1000 MW.

NPCC: Type III

An SPS whose misoperation or failure to operate results in no **significant adverse impact** outside the **local area**.

The following terms are also defined by NPCC to assess the impact of the SPS for classification:

Significant adverse impact – With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from faults or disturbances, shall be deemed as having significant adverse impact:

a. system instability;
b. unacceptable system dynamic response or equipment tripping;
c. voltage levels in violation of applicable emergency limits;
d. loadings on transmission facilities in violation of applicable emergency limits;
e. unacceptable loss of load.

Local area – An electrically confined or radial portion of the system. The geographic size and number of system elements contained will vary based on system characteristics. A local area may be relatively large geographically with relatively few buses in a sparse system, or be

[7] WECC Procedure to Submit a RAS for Assessment Information Required to Assess the Reliability of a RAS Guideline, Revised 10/28/2013 | NPCC Regional Reliability Reference Directory # 7, Special Protection Systems, Version 2, 3/31/2015

relatively small geographically with a relatively large number of buses in a densely networked system.

A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type III in NPCC, is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.

To propose an existing RAS (a RAS implemented prior to the effective date of PRC-012-2) be designated as limited impact by the reviewing RC, the RAS-entity must prepare and submit the appropriate Attachment 1 information that includes the technical justification (evaluations) documenting that the System can meet the performance requirements (specified in Requirement R4, Parts 4.1.4 and 4.1.5) resulting from a single RAS component malfunction or failure, respectively.

There is nothing that precludes a RAS-entity from working with the reviewing RC during the implementation period of PRC-012-2, in anticipation of the standard becoming enforceable. However, even if the reviewing RC determines the RAS qualifies as limited impact, the designation is not relevant until the standard becomes effective. Until then, the existing regional processes remain in effect as well as the existing RAS classifications or lack thereof.

An example of a scheme that could be recognized as a limited impact RAS is a load shedding or generation rejection scheme used to mitigate the overload of a BES transmission line. The inadvertent operation of such a scheme would cause the loss of either a certain amount of generation or load. The evaluation by the RAS-entity should demonstrate that the loss of this amount of generation or load, without the associated contingency for RAS operation actually occurring, is acceptable and not detrimental to the reliability of BES; e.g., in terms of frequency and voltage stability. The failure of that scheme to operate when intended could potentially lead to the overloading of a transmission line beyond its acceptable rating. The RAS-entity would need to demonstrate that this overload, while in excess of the applicable Facility Rating, is not detrimental to the BES outside the contained area (predetermined by studies) affected by the contingency.

Other examples of limited impact RAS include:

- A scheme used to protect BES equipment from damage caused by overvoltage through generation rejection or equipment tripping.
- A centrally-controlled undervoltage load shedding scheme used to protect a contained area (predetermined by studies) of the BES against voltage collapse.
- A scheme used to trip a generating unit following certain BES Contingencies to prevent the unit from going out of synch with the System; where, if the RAS fails to operate and the unit pulls out of synchronism, the resulting apparent impedance swings do not

result in the tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities.

Requirement R1

Each RAS is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES); therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification, or retirement (removal from service) must be completed prior to implementation.

Functional modifications consists of any of the following:

- Changes to System conditions or Contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

An example indicating the limits of an in-kind replacement of a RAS component is the replacement of one relay (or other device) with a relay (or other device) that uses similar functions. For instance, if a RAS included a CO-11 relay which was replaced by an IAC-53 relay, that would be an in-kind replacement. If the CO-11 relay were replaced by a microprocessor SEL-451 relay that used only the same functions as the original CO-11 relay, that would also be an in-kind replacement; however, if the SEL-451 relay was used to add new logic to what the CO-11 relay had provided, then the replacement relay would be a functional modification.

Changes to RAS pickup levels that require no other scheme changes are not considered a functional modification. For example, System conditions require a RAS to be armed when the combined flow on two lines exceeds 500 MW. If a periodic evaluation pursuant to Requirement R4, or other assessment, indicates that the arming level should be reduced to 450 MW without requiring any other RAS changes that would not be a functional modification. Similarly, if a RAS is designed to shed load to reduce loading on a particular line below 1000 amps, then a change in the load shedding trigger from 1000 amps to 1100 amps would not be a functional modification.

Another example illustrates a case where a System change may result in a RAS functional change. Assume that a generation center is connected to a load center through two transmission lines. The lines are not rated to accommodate full plant output if one line is out of service, so a RAS monitors the status of both lines and trips or ramps down the generation to a safe level following loss of either line. Later, one of the lines is tapped to serve additional load. The System that the RAS impacts now includes three lines, loss of any of which is likely to still require generation reduction. The modified RAS will need to monitor all three lines (add two line terminal status inputs to the RAS) and the logic to recognize the specific line outages would change, while the generation reduction (RAS output) requirement may or may not change, depending on which line is out of service. These required RAS changes would be a functional modification.

Any functional modification to a RAS will need to be reviewed and approved through the process described in Requirements R1, R2, and R3. The need for such functional modifications may be identified in several ways including but not limited to the Planning evaluations pursuant to R4, incorrect operations pursuant to R5, a test failure pursuant to R8, or Planning assessments related to future additions or modifications of other facilities.

See Item 4a in the Implementation Section of Attachment 1 in the Supplemental Material section for typical RAS components for which a failure may be considered. The RC has the discretion to make the final determination regarding which components should be regarded as RAS components during its review.

To facilitate a review that promotes reliability, the RAS-entity(ies) must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity(ies) provide them to the reviewing Reliability Coordinator (RC). The RC that coordinates the area where the RAS is located is responsible for the review. In cases where a RAS crosses multiple RC Area boundaries, each affected RC is responsible for conducting either individual reviews or a coordinated review.

Requirement R1 does not specify how far in advance of implementation the RAS-entity(ies) must provide Attachment 1 data to the reviewing RC. The information will need to be submitted early enough to allow RC review in the allotted time pursuant to Requirement R2, including resolution of any reliability issues that might be identified, in order to obtain approval of the reviewing RC. Expeditious submittal of this information is in the interest of each RAS-entity to effect a timely implementation.

Requirement R2

Requirement R2 mandates that the RC perform reviews of all proposed new RAS and existing RAS proposed for functional modification, or retirement (removal from service) in its RC Area.

RAS are unique and customized assemblages of protection and control equipment. As such, they have a potential to introduce reliability risks to the BES, if not carefully planned, designed, and installed. A RAS may be installed to address a reliability issue, or achieve an economic or operational advantage, and could introduce reliability risks that might not be apparent to a RAS-entity(ies). An independent review by a multi-disciplinary panel of subject matter experts with planning, operations, protection, telecommunications, and equipment expertise is an effective means of identifying risks and recommending RAS modifications when necessary.

The RC is the functional entity best suited to perform the RAS reviews because it has the widest area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. This Wide Area purview facilitates the evaluation of interactions among separate RAS as well as interactions among the 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, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC may request assistance in RAS reviews from other parties such as the PC(s) or regional technical groups (e.g., Regional Entities); however, the RC retains responsibility for compliance with the requirement. It is recognized that the RC does not possesses more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not contain compliance requirements. If Reliability Standards address functions that are not described in the model, the Reliability Standard requirements take precedence over the Functional Model. For further reference, please see the Introduction section of NERC’s Reliability Functional Model, Version 5, November 2009. Attachment 2 of this standard is a checklist for assisting the RC in identifying design and implementation aspects of a RAS, and for facilitating consistent reviews of each RAS submitted for review. The time frame of four full calendar months is consistent with current utility practice; however, flexibility is provided by allowing the parties to negotiate a different schedule for the review. Note, an RC may need to include this task in its reliability plan(s) for the NERC Region(s) in which it is located.

Requirement R3

Requirement R3 mandates that each RAS-entity resolve all reliability issues (pertaining to its RAS) identified during the RAS review by the reviewing Reliability Coordinators. Examples of reliability issues include a lack of dependability, security, or coordination. RC approval of a RAS is considered to be obtained when the reviewing RC’s feedback to each RAS-entity indicates that either no reliability issues were identified during the review or all identified reliability issues were resolved to the RC’s satisfaction.

Dependability is a component of reliability that is the measure of certainty of a device to operate when required. If a RAS is installed to meet performance requirements of NERC Reliability Standards, a failure of the RAS to operate when intended would put the System at risk of violating NERC Reliability Standards if specified Contingency(ies) or System conditions occur. This risk is mitigated by designing the RAS so that it will accomplish the intended purpose while experiencing a single RAS component failure. This is often accomplished through redundancy. Other strategies for providing dependability include “over-tripping” load or generation, or alternative automatic backup schemes.

Security is a component of reliability that is the measure of certainty of a device to not operate inadvertently. False or inadvertent operation of a RAS results in taking a programmed action without the appropriate arming conditions, occurrence of specified Contingency(ies), or System conditions expected to trigger the RAS action. Typical RAS actions include shedding load or generation or re-configuring the System. Such actions, if inadvertently taken, are undesirable and may put the System in a less secure state. Worst case impacts from inadvertent operation often occur if all programmed RAS actions occur. If the System performance still satisfies PRC-012-2 Requirement R4, Part 4.3, no additional mitigation is required. Security enhancements to the RAS design, such as voting schemes, are acceptable mitigations against inadvertent operations.

Any reliability issue identified during the review must be resolved before implementing the RAS to avoid placing the System at unacceptable risk. The RAS-entity or the reviewing RC(s) may have alternative ideas or methods available to resolve the issue(s). In either case, the concern needs to be resolved in deference to reliability, and the RC has the final decision.

A specific time period for the RAS-entity to respond to the RC(s) review is not necessary because an expeditious response is in the interest of each RAS-entity to effect a timely implementation.

A specific time period for the RC to respond to the RAS-entity following the RAS review is also not necessary because the RC will be aware of (1) any reliability issues associated with the RAS not being in service and (2) the RAS-entity's schedule to implement the RAS to address those reliability issues. Since the RC is the ultimate arbiter of BES operating reliability, resolving reliability issues is a priority for the RC and serves as an incentive to expeditiously respond to the RAS-entity.

Requirement R4

Requirement R4 mandates that an evaluation of each RAS be performed at least once every five full calendar years. The purpose of a periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that requirements for BES performance following inadvertent RAS operation and single component failure continue to be satisfied. A periodic evaluation is required because changes in System topology or operating conditions may change the effectiveness of a RAS or the way it interacts with and impacts the BES.

A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. Limited impact RAS are not subject to the RAS single component malfunction and failure tests of Parts 4.1.4 and 4.1.5, respectively. Requiring a limited impact RAS to meet these tests would add complexity to the design with minimal benefit to BES reliability.

A RAS implemented after the effective date of this standard can only be designated as limited impact by the reviewing RC(s). A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type III in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.

Requirement R4 also clarifies that the RAS single component failure and inadvertent operation tests do not apply to RAS which are determined to be limited impact. Requiring a limited impact RAS to meet the single component failure and inadvertent operation tests would just add complexity to the design with little or no improvement in the reliability of the BES.

For existing RAS, the initial performance of Requirement R4 must be completed within five full calendar years of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within five full calendar years of the RAS approval date by the reviewing RC(s). Five full calendar years was selected as the maximum time frame between evaluations based on the time frames for similar requirements in Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation can be performed sooner if it is determined that material changes to System topology or System operating conditions could potentially impact the effectiveness or coordination of the RAS. System changes also have the potential to alter the reliability impact of limited impact RAS on the BES. Requirement 4, Part 4.1.3 explicitly requires the periodic evaluation of limited impact RAS to verify the limited impact designation remains applicable. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluations (Requirement R4, Parts 4.1.1 through 4.1.5) are planning analyses that may involve modeling of the interconnected transmission system to assess BES performance. The PC is the functional entity best suited to perform the analyses because they have a wide-area planning perspective. To promote reliability, the PC is required to provide the results of the evaluation to each impacted Transmission Planner and Planning Coordinator, in addition to each reviewing RC and RAS-entity. In cases where a RAS crosses PC boundaries, each affected PC is responsible for conducting either individual evaluations or participating in a coordinated evaluation.

The intent of Requirement R4, Part 4.1.4 is to verify that the possible inadvertent operation of the RAS (other than limited impact RAS), caused by the malfunction of a single component of the RAS, meet the same System performance requirements as those required for the Contingency(ies) or System conditions for which it is designed. If the RAS is designed to meet one of the planning events (P0-P7) in TPL-001-4, the possible inadvertent operation of the RAS must meet the same performance requirements listed in the standard for that planning event. The requirement clarifies that the inadvertent operation to be considered is only that caused by the malfunction of a single RAS component. This allows features to be designed into the RAS to improve security, such that inadvertent operation due to malfunction of a single component is prevented; otherwise, the RAS inadvertent operation must satisfy Requirement R4, Part 4.1.4.

The intent of Requirement R4, Part 4.1.4 is also to verify that the possible inadvertent operation of the RAS (other than limited impact RAS) installed for an extreme event in TPL-001-4 or for some other Contingency or System conditions not defined in TPL-001-4 (therefore without performance requirements), meet the minimum System performance requirements of Category P7 in Table 1 of NERC Reliability Standard TPL-001-4. However, instead of referring to the TPL standard, the requirement lists the System performance requirements that a potential inadvertent operation must satisfy. The performance requirements listed (Requirement R4, Parts 4.1.4.1 – 4.1.4.5) are the ones that are common to all planning events (P0-P7) listed in TPL-001-4.

With reference to Requirement 4, Part 4.1.4, note that the only differences in performance requirements among the TPL (P0-P7) events (not common to all of them) concern Non-Consequential Load Loss and interruption of Firm Transmission Service. It is not necessary for Requirement R4, Part 4.1.4 to specify performance requirements related to these areas because a RAS is only allowed to drop non-consequential load or interrupt Firm Transmission Service if that action is allowed for the Contingency for which it is designed. Therefore, the inadvertent operation should automatically meet Non-Consequential Load Loss or interrupting Firm Transmission Service performance requirements for the Contingency(ies) for which it was designed.

The intent of Requirement R4, Part 4.1.5 is to verify that a single component failure in a RAS, other than limited impact 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 is designed. This analysis is needed to ensure that changing System conditions do not result in the single component failure requirement not being met.

The following is an example of a single component failure causing the System to fail to meet the performance requirements for the P1 event for which the RAS was installed. Consider the instance where a three-phase Fault (P1 event) results in a generating plant becoming unstable (a violation of the System performance requirements of TPL-001-4). To resolve this, a RAS is installed to trip a single generating unit which allows the remaining units at the plant to remain stable. If failure of a single component (e.g., relay) in the RAS results in the RAS failing to operate for the P1 event, the generating plant would become unstable (failing to meet the System performance requirements of TPL-001-4 for a P1 event).

Requirement R4, Part 4.1.5 does not mandate that all RAS have redundant components. For example:

- Consider the instance where a RAS is installed to mitigate an extreme event in TPL-001-4. There are no System performance requirements for extreme events; therefore, the RAS does not need redundancy to meet the same performance requirements as those required for the events and conditions for which the RAS was designed.
- Consider a RAS that arms more load or generation than necessary such that failure of the RAS to drop a portion of load or generation due to that single component failure will still result in satisfactory System performance, as long as tripping the total armed amount of load or generation does not cause other adverse impacts to reliability.

The scope of the periodic evaluation does not include a new review of the physical implementation of the RAS, as this was confirmed by the RC during the initial review and verified by subsequent functional testing. However, it is possible that a RAS design which previously satisfied requirements for inadvertent RAS operation and single component failure by means other than component redundancy may fail to satisfy these requirements at a later time, and must be evaluated with respect to the current System. For example, if the actions of a particular RAS include tripping load, load growth could occur over time that impacts the amount of load to be tripped. These changes could result in tripping too much load upon inadvertent operation and result in violations of Facility Ratings. Alternatively, the RAS might be designed to trip more load than necessary (i.e., "over trip") in order to satisfy single component failure requirements. System changes could result in too little load being tripped and unacceptable BES performance if one of the loads failed to trip.

Requirement R5

The correct operation of a RAS is important to maintain the reliability and integrity of the BES. Any incorrect operation of a RAS indicates the RAS effectiveness and/or coordination may have been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: (1) verify RAS operation is consistent with implemented design; or (2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120 full calendar day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation; however, flexibility is provided by allowing the parties to negotiate a different schedule for the analysis. To promote reliability, the RAS-entity(s) is required to provide the results of RAS operational performance analyses to its reviewing RC(s) if the analyses revealed a deficiency.

The RAS-entity(ies) may need to collaborate with its associated Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation was triggered correctly (Part 5.1.1), responded as designed (Part 5.1.2), and that the resulting BES response (Parts 5.1.3 and 5.1.4) was consistent with the intended functionality and design of the RAS. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to conduct and submit a single, coordinated operational performance analysis.

Requirement R6

RAS deficiencies potentially pose a reliability risk to the BES. RAS deficiencies may be identified in the periodic RAS evaluation conducted by the PC in Requirement R4, in the operational analysis conducted by the RAS-entity in Requirement R5, or in the functional test performed by the RAS-entity(ies) in Requirement R8. To mitigate potential reliability risks, Requirement R6

mandates that each RAS-entity participate in developing a CAP that establishes the mitigation actions and timetable necessary to address the deficiency.

The RAS-entity(ies) that owns the RAS components, is responsible for the RAS equipment, and is in the best position to develop the timelines and perform the necessary work to correct RAS deficiencies. If necessary, the RAS-entity(ies) may request assistance with development of the CAP from other parties such as its Transmission Planner or Planning Coordinator; however, the RAS-entity has the responsibility for compliance with this requirement.

A CAP may require functional changes be made to a RAS. In this case, Attachment 1 information must be submitted to the reviewing RC(s), an RC review must be performed to obtain RC approval before the RAS-entity can place RAS modifications in service, per Requirements R1, R2, and R3.

Depending on the complexity of the issues, development of a CAP may require study, engineering or consulting work. A timeframe of six full calendar months is allotted to allow enough time for RAS-entity collaboration on the CAP development, while ensuring that deficiencies are addressed in a reasonable time. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to develop and submit a single, coordinated CAP. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the RAS deficiency is resolved. The possibility of such operating restrictions will incent the RAS-entity to resolve the issue as quickly as possible.

The following are example situations of when a CAP is required:

- A determination after a RAS operation/non-operation investigation that the RAS did not meet performance expectations or did not operate as designed.
- Periodic planning assessment reveals RAS changes are necessary to correct performance or coordination issues.
- Equipment failures.
- Functional testing identifies that a RAS is not operating as designed.

Requirement R7

Requirement R7 mandates that each RAS-entity implement its CAP developed in Requirement R6 which mitigates the deficiencies identified in Requirements R4, R5, or R8. By definition, a CAP is: “A list of actions and an associated timetable for implementation to remedy a specific problem.”

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. If the CAP is changed, the RAS-entity must notify the reviewing Reliability

Coordinator(s). The RAS-entity must also notify the Reliability Coordinator(s) when the CAP has been completed.

The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions will incent the RAS-entity to complete the CAP as quickly as possible.

Requirement R8

The reliability objective of Requirement R8 is to test the non-Protection System components of a RAS (controllers such as programmable logic controllers (PLCs)) and to verify the overall performance of the RAS through functional testing. Functional tests validate RAS operation by ensuring System states are detected and processed, and that actions taken by the controls are correct and occur within the expected time using the in-service settings and logic. Functional testing is aimed at assuring overall RAS performance and not the component focused testing contained in the PRC-005 maintenance standard.

Since the functional test operates the RAS under controlled conditions with known System states and expected results, testing and analysis can be performed with minimum impact to the BES and should align with expected results. The RAS-entity is in the best position to determine the testing procedure and schedule due to their overall knowledge of the RAS design, installation, and functionality. Periodic testing provides the RAS-entity assurance that latent failures may be identified and also promotes identification of changes in the System that may have introduced latent failures.

The six and twelve full calendar year functional testing intervals are greater than the annual or bi-annual periodic testing performed in some NERC Regions. However, these intervals are a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS. Longer test intervals for limited impact RAS are acceptable because incorrect operations or failures to operate present a low reliability risk to the Bulk Power System.

Functional testing is not synonymous with end-to-end testing. End-to-end testing is an acceptable method but may not be feasible for many RAS. When end-to-end testing is not possible, a RAS-entity may use a segmented functional testing approach. The segments can be tested individually negating the need for complex maintenance schedules. In addition, actual RAS operation(s) can be used to fulfill the functional testing requirement. If a RAS does not operate in its entirety during a System event or System conditions do not allow an end-to-end scheme test, then the segmented approach should be used to fulfill this Requirement. Functional testing includes the testing of all RAS inputs used for detection, arming, operating, and data collection. Functional testing, by default operates the processing logic and infrastructure of a RAS, but focuses on the RAS inputs as well as the actions initiated by RAS outputs to address the System condition(s) for which the RAS is designed. All segments and components of a RAS must be tested or have proven operations within the applicable maximum test interval to demonstrate compliance with the Requirement.

As an example of segment testing, consider a RAS controller implemented using a PLC that receives System data, such as loading or line status, from distributed devices. These distributed devices could include meters, protective relays, or other PLCs. In this example RAS, a line protective relay is used to provide an analog metering quantity to the RAS control PLC. A functional test would verify that the System data is received from the protective relay by the PLC, processed by the PLC, and that PLC outputs are appropriate. There is no need to verify the protective relay's ability to measure the power system quantities, as this is a requirement for Protection Systems used as RAS in PRC-005, Table 1-1, Component Type – Protective Relay. Rather the functional test is focused on the use of the protective relay data at the PLC, including the communications data path from relay to PLC if this data is essential for proper RAS operation. Additionally, if the control signal back to the protective relay is also critical to the proper functioning of this example RAS, then that path is also verified up to the protective relay. This example describes a test for one segment of a RAS which verifies RAS action, verifies PLC control logic, and verifies RAS communications.

IEEE C37.233, "IEEE Guide for Power System Protection Testing," 2009 section 8 (particularly 8.3-8.5), provides an overview of functional testing. The following opens section 8.3:

> Proper implementation requires a well-defined and coordinated test plan for performance evaluation of the overall system during agreed maintenance intervals. The maintenance test plan, also referred to as functional system testing, should include inputs, outputs, communication, logic, and throughput timing tests. The functional tests are generally not component-level testing, rather overall system testing. Some of the input tests may need to be done ahead of overall system testing to the extent that the tests affect the overall performance. The test coordinator or coordinators need to have full knowledge of the intent of the scheme, isolation points, simulation scenarios, and restoration to normal procedures.
>
> The concept is to validate the overall performance of the scheme, including the logic where applicable, to validate the overall throughput times against system modeling for different types of Contingencies, and to verify scheme performance as well as the inputs and outputs.

If a RAS passes a functional test, it is not necessary to provide that specific information to the RC because that is the expected result and requires no further action. If a segment of a RAS fails a functional test, the status of that degraded RAS is required to be reported (in Real-time) to the Transmission Operator via PRC-001, Requirement R6, then to the RC via TOP-001-3, Requirement R8. See Phase 2 of Project 2007-06 for the mapping document from PRC-001 to other standards regarding notification of RC by TOP if a deficiency is found during testing. Consequently, it is not necessary to include a similar requirement in this standard.

The initial test interval begins on the effective date of the standard pursuant to the implementation plan. Subsequently, the maximum allowable interval between functional tests is six full calendar years for RAS that are not designated as limited impact RAS and twelve full calendar years for RAS that are designated as limited impact RAS. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. A RAS-entity may choose to count a correct RAS operation as a qualifying functional test for those RAS segments which operate. If a System event causes a correct, but partial RAS operation, separate functional tests of the segments that did not operate are still required within the maximum test interval that started on the date of the previous successful test of those (non-operating) segments in order to be compliant with Requirement R8.

Requirement R9

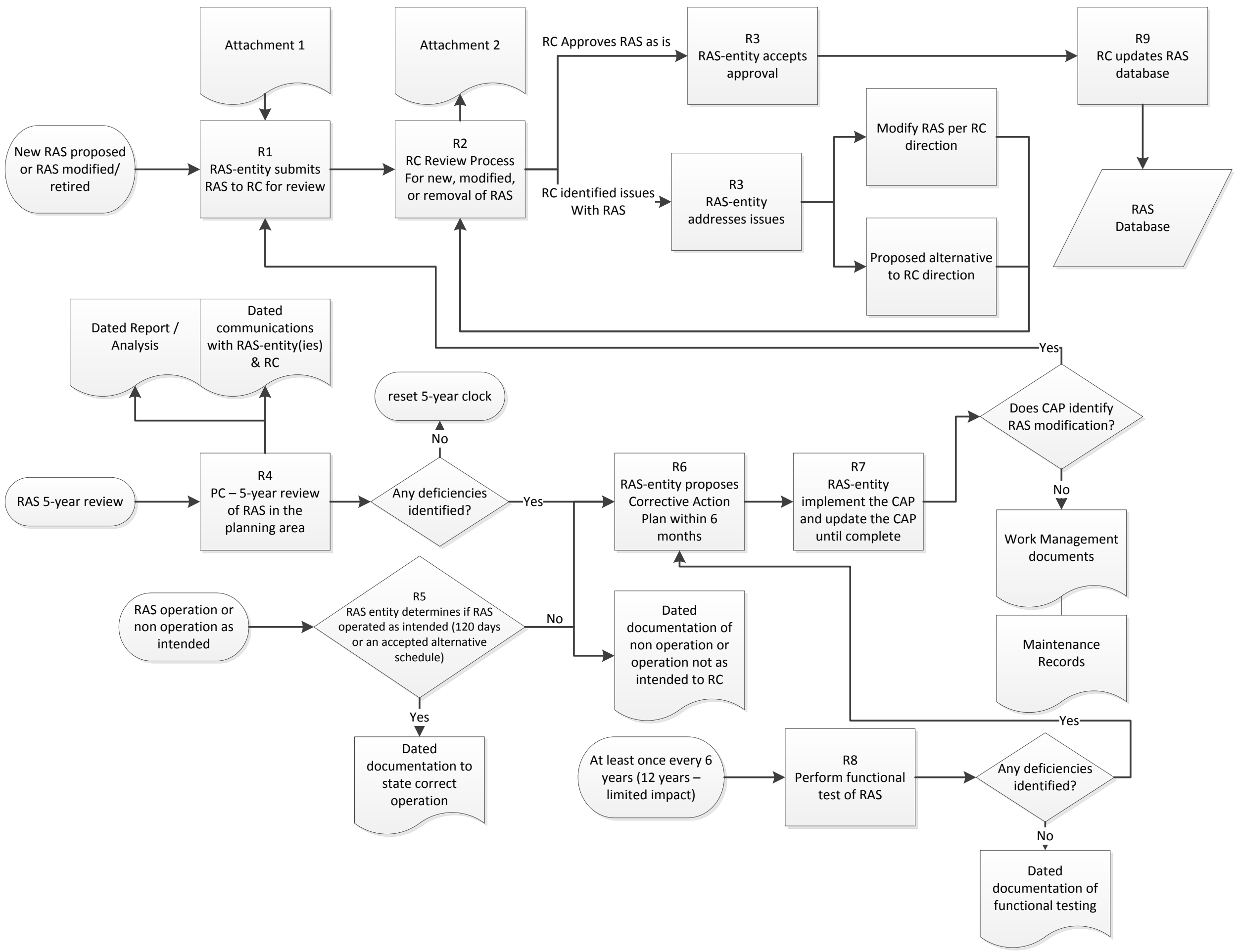
The RAS database required to be maintained by the RC in Requirement R9 ensures information regarding existing RAS is available. Attachment 3 contains the minimum information that is required to be included about each RAS listed in the database. Additional information can be requested by the RC.

The database enables the RC to provide other entities high-level information on existing RAS that could potentially impact the operational and/or planning activities of that entity. The information provided is sufficient for an entity with a reliability need to evaluate whether the RAS can impact its System. For example, a RAS performing generation rejection to mitigate an overload on a transmission line may cause a power flow change within an adjacent entity area. This entity should be able to evaluate the risk that a RAS poses to its System from the high-level information provided in the RAS database.

The RAS database does not need to list detailed settings or modeling information, but the description of the System performance issues, System conditions, and the intended corrective actions must be included. If additional details about the RAS operation are required, the entity may obtain the contact information of the RAS-entity from the RC.

Process Flow Diagram

The diagram below depicts the process flow of the PRC-012-2 requirements.



Technical Justifications for Attachment 1 Content
Supporting Documentation for RAS Review

To perform an adequate review of the expected reliability implications of a Remedial Action Scheme (RAS), it is necessary for the RAS-entity(ies) to provide a detailed list of information describing the RAS to the reviewing RC. If there are multiple RAS-entities for a single RAS, information will be needed from all RAS-entities. Ideally, in such cases, a single RAS-entity will take the lead to compile all the data identified into a single Attachment 1.

The necessary data ranges from a general overview of the RAS to summarized results of transmission planning studies, to information about hardware used to implement the RAS. Coordination between the RAS and other RAS and protection and control systems will be examined for possible adverse interactions. This review can include wide-ranging electrical design issues involving the specific hardware, logic, telecommunications, and other relevant equipment and controls that make up the RAS.

Attachment 1

The following checklist identifies important RAS information for each new or functionally modified[8] RAS that the RAS-entity shall document and provide to the RC for review pursuant to Requirement R1. When a RAS has been previously reviewed, only the proposed modifications to that RAS require review; however, it will be helpful to each reviewing RC if the RAS-entity provides a summary of the existing RAS functionality.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.

   Provide a description of the RAS to give an overall understanding of the functionality and a map showing the location of the RAS. Identify other protection and control systems requiring coordination with the RAS. See RAS Design below for additional information.

   Provide a single-line drawing(s) showing all sites involved. The drawing(s) should provide sufficient information to allow the RC review team to assess design reliability, and should include information such as the bus arrangement, circuit breakers, the associated switches, etc. For each site, indicate whether detection, logic, action, or a combination of these is present.

2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.

[8] Functionally modified: Any modification to a RAS consisting of any of the following:

- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP. [Reference NERC Reliability Standard PRC-012-2, Requirements R5 and R7]

   Provide a description of any functional modifications to a RAS that are part of a CAP that are proposed to address performance deficiency(ies) identified in the periodic evaluation pursuant to Requirement R4, the analysis of an actual RAS operation pursuant to Requirement R5, or functional test failure pursuant to Requirement R8. A copy of the most recent CAP must be submitted in addition to the other data specified in Attachment 1.

4. Initial data to populate the RAS database.

   a. RAS name.

   b. Each RAS-entity and contact information.

   c. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent five full calendar year (Requirement R4) evaluation date; and, date of retirement, if applicable.

   d. System performance issue or reason for installing the RAS (*e.g.*, thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery).

   e. Description of the Contingencies or System conditions for which the RAS was designed (initiating conditions).

   f. Corrective action taken by the RAS.

   g. Identification of limited impact[9] RAS.

   h. Any additional explanation relevant to high level understanding of the RAS.

   Note: This is the same information as is identified in Attachment 3. Supplying the data at this point in the review process ensures a more complete review and minimizes any administrative burden on the reviewing RC(s).

II. Functional Description and Transmission Planning Information

1. Contingencies and System conditions that the RAS is intended to remedy. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.1]

   a. The System conditions that would result if no RAS action occurred should be identified.

   b. Include a description of the System conditions that should arm the RAS so as to be ready to take action upon subsequent occurrence of the critical System Contingencies or other operating conditions when RAS action is intended to occur. If no arming conditions are required, this should also be stated.

[9] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

   c. Event-based RAS are triggered by specific Contingencies that initiate mitigating action. Condition-based RAS may also be initiated by specific Contingencies, but specific Contingencies are not always required. These triggering Contingencies and/or conditions should be identified.

2. The actions to be taken by the RAS in response to disturbance conditions. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.2]

   Mitigating actions are designed to result in acceptable System performance. These actions should be identified, including any time constraints and/or "backup" mitigating measures that may be required in case of a single RAS component failure.

3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and the date those technical studies were performed. [Reference NEC Reliability Standard PRC-014, R3.2]

   Review the scheme purpose and impact to ensure it is (still) necessary, serves the intended purposes, and meets current performance requirements. While copies of the full, detailed studies may not be necessary, any abbreviated descriptions of the studies must be detailed enough to allow the reviewing RC(s) to be convinced of the need for the scheme and the results of RAS-related operations.

4. Information regarding any future System plans that will impact the RAS. [Reference NERC Reliability Standard PRC-014, R3.2]

   The RC's other responsibilities under the NERC Reliability Standards focus on the Operating Horizon, rather than the Planning Horizon. As such, the RC is less likely to be aware of any longer range plans that may have an impact on the proposed RAS. Such knowledge of future Plans is helpful to provide perspective on the capabilities of the RAS.

5. RAS-entity proposal and justification for limited impact designation, if applicable.

   A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type 3 in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.

6. Documentation describing the System performance resulting from the possible inadvertent operation of the RAS, except for limited impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be limited impact must satisfy all of the following: [Reference NERC Reliability Standard PRC-012, R1.4]

a. The BES shall remain stable.

b. Cascading shall not occur.

c. Applicable Facility Ratings shall not be exceeded.

d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

7. An evaluation indicating that the RAS settings and operation avoids adverse interactions with other RAS, and protection and control systems.
[Reference NERC Reliability Standards PRC-012, R1.5 and PRC-014, R3.4]

   RAS are complex schemes that may take action such as tripping load or generation or re-configuring the System. Many RAS depend on sensing specific System configurations to determine whether they need to arm or take actions. An examples of an adverse interaction: A RAS that reconfigures the System also changes the available Fault duty, which can affect distance relay overcurrent ("fault detector") supervision and ground overcurrent protection coordination.

8. Identification of other affected RCs.

   This information is needed to aid in information exchange among all affected entities and coordination of the RAS with other RAS and protection and control systems.

III. Implementation

1. Documentation describing the applicable equipment used for detection, dc supply, communications, transfer trip, logic processing, control actions, and monitoring.

   Detection
   Detection and initiating devices, whether for arming or triggering action, should be designed to be secure. Several types of devices have been commonly used as disturbance, condition, or status detectors:

   - Line open status (event detectors),
   - Protective relay inputs and outputs (event and parameter detectors),
   - Transducer and IED (analog) inputs (parameter and response detectors),
   - Rate of change (parameter and response detectors).

   DC Supply
   Batteries and charges, or other forms of dc supply for RAS, are commonly also used for Protection Systems. This is acceptable, and maintenance of such supplies is covered by PRC-005. However, redundant RAS, when used, should be supplied from separately protected (fused or breakered) circuits.

Communications: Telecommunications Channels

Telecommunications channels used for sending and receiving RAS information between sites and/or transfer trip devices should meet at least the same criteria as other relaying protection communication channels. Discuss performance of any non-deterministic communication systems used (such as Ethernet).

The scheme logic should be designed so that loss of the channel, noise, or other channel or equipment failure will not result in a false operation of the scheme.

It is highly desirable that the channel equipment and communications media (power line carrier, microwave, optical fiber, etc.) be owned and maintained by the RAS-entity, or perhaps leased from another entity familiar with the necessary reliability requirements. All channel equipment should be monitored and alarmed to the dispatch center so that timely diagnostic and repair action shall take place upon failure. Publicly switched telephone networks are generally an undesirable option.

Communication channels should be well labeled or identified so that the personnel working on the channel can readily identify the proper circuit. Channels between entities should be identified with a common name at all terminals.

Transfer Trip

Transfer trip equipment, when separate from other RAS equipment, should be monitored and labeled similarly to the channel equipment.

Logic Processing

All RAS require some form of logic processing to determine the action to take when the scheme is triggered. Required actions are always scheme dependent. Different actions may be required at different arming levels or for different Contingencies. Scheme logic may be achievable by something as simple as wiring a few auxiliary relay contacts or by much more complex logic processing.

Platforms that have been used reliably and successfully include PLCs in various forms, personal computers (PCs), microprocessor protective relays, remote terminal units (RTUs), and logic processors. Single-function relays have been used historically to implement RAS, but this approach is now less common except for very simple new RAS or minor additions to existing RAS.

Control Actions

RAS action devices may include a variety of equipment such as transfer trip, protective relays, and other control devices. These devices receive commands from the logic processing function (perhaps through telecommunication facilities) and initiate RAS actions at the sites where action is required.

Monitoring by SCADA/EMS should include at least

- Whether the scheme is in service or out of service.
    - For RAS that are armed manually, the arming status may be the same as whether the RAS is in service or out of service.

    - For RAS that are armed automatically, these two states are independent because a RAS that has been placed in service may be armed or unarmed based on whether the automatic arming criteria have been met.

- The current operational state of the scheme (available or not).
- In cases where the RAS requires single component failure performance; e.g., redundancy, the minimal status indications should be provided separately for each RAS.
    - The minimum status is generally sufficient for operational purposes; however, where possible it is often useful to provide additional information regarding partial failures or the status of critical components to allow the RAS-entity to more efficiently troubleshoot a reported failure. Whether this capability exists will depend in part on the design and vintage of equipment used in the RAS. While all schemes should provide the minimum level of monitoring, new schemes should be designed with the objective of providing monitoring at least similar to what is provided for microprocessor-based Protection Systems.

2. Information on detection logic and settings/parameters that control the operation of the RAS. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.3]

   Several methods to determine line or other equipment status are in common use, often in combination:

   a. Auxiliary switch contacts from circuit breakers and disconnect switches (52a/b, 89a/b)—the most common status monitor; "a" contacts exactly emulate actual breaker status, while "b" contacts are opposite to the status of the breaker;
   b. Undercurrent detection—a low level indicates an open condition, including at the far end of a line; pickup is typically slightly above the total line-charging current;
   c. Breaker trip coil current monitoring—typically used when high-speed RAS response is required, but usually in combination with auxiliary switch contacts and/or other detection because the trip coil current ceases when the breaker opens; and
   d. Other detectors such as angle, voltage, power, frequency, rate of change of the aforementioned, out of step, etc. are dependent on specific scheme requirements, but some forms may substitute for or enhance other monitoring described in items 'a', 'b', and 'c' above.

   Both RAS arming and action triggers often require monitoring of analog quantities such as power, current, and voltage at one or more locations and are set to detect a specific level of the pertinent quantity. These monitors may be relays, meters, transducers, or other devices

3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in service or is being maintained.

In this context, a multifunction device (e.g., microprocessor-based relay) is a single component that is used to perform the function of a RAS in addition to protective relaying and/or SCADA simultaneously. It is important that other applications in the multifunction device do not compromise the functionality of the RAS when the device is in service or when it is being maintained. The following list outlines considerations when the RAS function is applied in the same microprocessor-based relay as equipment protection functions:

a. Describe how the multifunction device is applied in the RAS.

b. Show the general arrangement and describe how the multi-function device is labeled in the design and application, so as to identify the RAS and other device functions.

c. Describe the procedures used to isolate the RAS function from other functions in the device.

d. Describe the procedures used when each multifunction device is removed from service and whether coordination with other protection schemes is required.

e. Describe how each multifunction device is tested, both for commissioning and during periodic maintenance testing, with regard to each function of the device.

f. Describe how overall periodic RAS functional and throughput tests are performed if multifunction devices are used for both local protection and RAS.

g. Describe how upgrades to the multifunction device, such as firmware upgrades, are accomplished. How is the RAS function taken into consideration?

Other devices that are usually not considered multifunction devices such as auxiliary relays, control switches, and instrument transformers may serve multiple purposes such as protection and RAS. Similar concerns apply for these applications as noted above.

4. Documentation describing the System performance resulting from a single component failure in the RAS, except for limited impact RAS, when the RAS is intended to operate. A single component failure in a RAS not determined to be limited impact must 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 is designed. The documentation should describe or illustrate how the design achieves this objective. [Reference NERC Reliability Standard PRC-012, R1.3]

   RAS automatic arming, if applicable, is vital to RAS and System performance and is therefore included in this requirement.

   Acceptable methods to achieve this objective include, but are not limited to the following:

   a. Providing redundancy of RAS components. Typical examples are listed below:

      i. Protective or auxiliary relays used by the RAS.

ii. Communications systems necessary for correct operation of the RAS.

iii. Sensing devices used to measure electrical or other quantities used by the RAS.

iv. Station dc supply associated with RAS functions.

v. Control circuitry associated with RAS functions through the trip coil(s) of the circuit breakers or other interrupting devices.

vi. Logic processing devices that accept System inputs from RAS components or other sources, make decisions based on those inputs, or initiate output signals to take remedial actions.

b. Arming more load or generation than necessary such that failure of the RAS to drop a portion of load or generation due to that single component failure will still result in satisfactory System performance, as long as tripping the total armed amount of load or generation does not cause other adverse impacts to reliability.

c. Using alternative automatic actions to back up failures of single RAS components.

d. 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.

5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies important RAS information for each existing RAS to be retired that the RAS-entity shall document and provide to the Reliability Coordinator for review pursuant to Requirement R1.

1. Information necessary to ensure that the Reliability Coordinator is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of technical studies and technical justifications, if applicable, upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

While the documentation necessary to evaluate RAS removals is not as extensive as for new or functionally modified RAS, it is still vital that, when the RAS is no longer available, System performance will still meet the appropriate (usually TPL) requirements for the Contingencies or System conditions that the RAS had been installed to remediate.

Technical Justification for Attachment 2 Content

Reliability Coordinator RAS Review Checklist

Attachment 2 is a checklist provided to facilitate consistent reviews continent-wide for new or functionally modified RAS prior to the RAS installation. The checklist is meant to assist the RC in identifying reliability-related considerations relevant to various aspects of RAS design and implementation.

Technical Justifications for Attachment 3 Content

Database Information

Attachment 3 contains the minimum information that the RC must consolidate into its database for each RAS in its area.

1. RAS name.
   - The name used to identify the RAS.
2. Each RAS-entity and contact information.
   - A reliable phone number or email address should be included to contact each RAS-entity if more information is needed.
3. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent five full calendar year (Requirement R4) evaluation date; and, date of retirement, if applicable.
   - Specify each applicable date.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery).
   - A short description of the reason for installing the RAS is sufficient, as long as the main System issues addressed by the RAS can be identified by someone with a reliability need.
5. Description of the Contingencies or System conditions for which the RAS was designed (initiating conditions).
   - A high level summary of the conditions/Contingencies is expected. Not all combinations of conditions are required to be listed.
6. Corrective action taken by the RAS.
   - A short description of the actions should be given. For schemes shedding load or generation, the maximum amount of megawatts should be included.

7. Identification of limited impact[10] RAS.
   - Specify whether or not the RAS is designated as limited impact.
8. Any additional explanation relevant to high-level understanding of the RAS.
   - If deemed necessary, any additional information can be included in this section, but is not mandatory.

[10] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

Draft ~~2~~3 of PRC-012-2 corrects the applicability of the fill-in-the-blank standards (PRC-012-1, PRC-013-1, and PRC-014-1) by assigning the requirement responsibilities to the specific users, owners, and operators of the Bulk-Power System, and incorporates the reliability objectives of all the RAS-related standards. This draft contains nine requirements and measures, the associated rationale boxes and corresponding technical guidelines. There are also three attachments within the draft standard that are incorporated via references in the requirements. This draft of PRC-012-2 is posted for a ~~45~~10-day ~~formal comment period with a parallel~~final ballot~~ in the last ten days of the comment period~~.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	February 12, 2014
SAR posted for comment	February 18, 2014
Standards Committee approved the SAR	June 10, 2014
Draft 1 of PRC-012-2 posted for informal comment	April 30 – May 20, 2015
Draft 1 of PRC-012-2 posted for 45-day formal comment period with initial ballot	August 20 – October 5, 2015
Draft 2 of PRC-012-2 posted for 45-day formal comment period with additional ballot	November 25, 2015 – January 8, 2016
Draft 3 of PRC-012-2 posted for 45-day formal comment period with additional ballot	February 3, 2016 – March 18, 2016
Draft 3 of PRC-012-2 posted for 10-day final ballot.	April 20 – 29, 2016

Anticipated Actions	Date
~~10-day final ballot~~	~~April 2016~~
Adoption by Board of Trustees~~NERC Board (Board) adoption~~	May 2016

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Remedial Action Schemes
2. **Number:** PRC-012-2
3. **Purpose:** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).
4. **Applicability:**
    - **4.1. Functional Entities:**
        - **4.1.1.** Reliability Coordinator
        - **4.1.2.** Planning Coordinator
        - **4.1.3.** RAS-entity – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS
    - **4.2. Facilities:**
        - **4.2.1.** Remedial Action Schemes (RAS)
5. **Effective Date:** See the Implementation Plan for PRC-012-2.

B. Requirements and Measures

Rationale for Requirement R1: Each Remedial Action Scheme (RAS) is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES). Therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification or retirement; i.e., removal from service must be completed prior to implementation or retirement.

Functional modifications consist of any of the following:

- Changes to System conditions or Contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

To facilitate a review that promotes reliability, the RAS-entity must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity provide them to the reviewing Reliability Coordinator (RC). The RC (reviewing RC) that coordinates the area where the RAS is located is responsible for the review. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate and submit a single, coordinated Attachment 1 to the reviewing RC. In cases where a RAS crosses RC Area boundaries, each affected RC is responsible for conducting either individual reviews or participating in a coordinated review.

R1. Prior to placing a new or functionally modified RAS in~~-~~ service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, a copy of the Attachment 1 documentation and the dated communications with the reviewing Reliability Coordinator(s) in accordance with Requirement R1.

Rationale for Requirement R2: The RC is the functional entity best suited to perform the RAS review because it has the widest~~-~~ area operational and reliability perspective of all functional entities and an awareness of reliability issues in any neighboring RC Area. This Wide Area purview facilitates the evaluation of interactions among separate RAS as well as interactions among RAS and other protection and control systems. Review by the RC also minimizes the possibility of a conflict of interest that could exist because of business relationships among the RAS-entity, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC is not expected to possess more information or ability than anticipated by their

functional registration as designated by NERC. The RC may request assistance to perform RAS reviews from other parties such as the PC or regional technical groups; however, the RC will retain the responsibility for compliance with this requirement.

Attachment 2 of this standard is a checklist the RC can use to identify design and implementation aspects of RAS and facilitate consistent reviews for each submitted RAS. The time frame of four full calendar months is consistent with current utility and regional practice; however, flexibility is provided by allowing the RC(s) and RAS-entity(ies) to negotiate a mutually agreed upon schedule for the review.

Note: An RC may need to include this task in its reliability plan(s) for the NERC Regions(s) in which it is located.

R2. Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated reports, checklists, or other documentation detailing the RAS review, and the dated communications with the RAS-entity in accordance with Requirement R2.

Rationale for Requirement R3: The RC review is intended to identify reliability issues that must be resolved before the RAS can be put in~~-~~ service. Examples of reliability issues include a lack of dependability, security, or coordination.

A specific time period for the RAS-entity to respond to the reviewing RC following identification of any reliability issue(s) is not necessary because the RAS-entity wants to expedite the timely approval and subsequent implementation of the RAS.

A specific time period for the RC to respond to the RAS-entity following the RAS review is also not necessary because the RC will be aware of (1) any reliability issues associated with the RAS not being in service and (2) the RAS-entity's schedule to implement the RAS to address those reliability issues. Since the RC is the ultimate arbiter of BES operating reliability, resolving reliability issues is a priority for the RC and serves as an incentive to expeditiously respond to the RAS-entity.

R3. Prior to placing a new or functionally modified RAS in~~-~~ service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Acceptable evidence may include, but is not limited to, dated documentation and communications with the reviewing Reliability Coordinator that no reliability issues

were identified during the review or that all identified reliability issues were resolved in accordance with Requirement R3.

Rationale for Requirement R4: Requirement R4 mandates that an evaluation of each RAS be performed at least once every five full calendar years. The purpose of the periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that, if a RAS single component malfunction or single component failure were to occur, the requirements for BES performance would continue to be satisfied. A periodic evaluation is required because changes in System topology or operating conditions may change the effectiveness of a RAS or the way it impacts the BES.

RAS are unique and customized assemblages of protection and control equipment that vary in complexity and impact on the reliability of the BES. In recognition of these differences, RAS can be designated by the reviewing RC(s) as limited impact. A limited impact RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. The "BES" qualifier in the preceding statement modifies all of the conditions that follow it. Limited impact RAS are not subject to the RAS single component malfunction and failure tests of Parts 4.1.4 and 4.1.5, respectively. Requiring a limited impact RAS to meet these tests would add complexity to the design with minimal benefit to BES reliability. See the Supplemental Material for more on the limited impact designation.

~~The limited impact designation is modeled after~~The standard recognizes the Local Area Protection Scheme (LAPS) classification in WECC (Western Electricity Coordinating Council) and the Type ~~3~~III classification in NPCC (Northeast Power Coordinating Council~~).~~) as initially appropriate for limited impact designation. A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type ~~3~~III in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.

For existing RAS, the initial performance of Requirement R4 must be completed within five full calendar years of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within five full calendar years of the RAS approval date by the reviewing RC(s). Five full calendar years was selected as the maximum time frame between evaluations based on the time frames for similar requirements in Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation can be performed sooner if it is determined that material changes to System topology or System operating conditions could potentially impact the effectiveness or coordination of the RAS. System changes also have the potential to alter the reliability impact of limited impact RAS on the BES. Requirement 4, Part 4.1.3 explicitly requires the periodic evaluation of limited impact RAS to verify the limited impact designation remains applicable~~.~~; the PC can use its discretion as to how this evaluation is performed. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluations (Requirement R4, Parts 4.1.1 through 4.1.5) are planning analyses that may involve modeling of the interconnected transmission system to assess BES performance. The Planning Coordinator (PC) is the functional entity best suited to perform this evaluation because they have a wide area planning perspective. To promote reliability, the PC is required to provide the results of the evaluation to each impacted Transmission Planner and Planning Coordinator, in addition to each reviewing RC and RAS-entity. In cases where a RAS crosses PC boundaries, each affected PC is responsible for conducting either individual evaluations or participating in a coordinated evaluation.

The previous version of this standard (PRC-012-1 Requirement 1, R1.4) states "… 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." Requirement R4 clarifies that the inadvertent operation to be considered would only be that caused by the malfunction of a single RAS component. This allows security features to be designed into the RAS such that inadvertent operation due to a single component malfunction is prevented. Otherwise, consistent with PRC-012-1 Requirement 1, R1.4, the RAS should be designed so that its whole or partial inadvertent operation due to a single component malfunction satisfies the System 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 some other Contingency or System condition not defined in TPL-001-4 (therefore without performance requirements), its inadvertent operation still must meet some minimum System performance requirements. However, instead of referring to the TPL-001-4, Requirement R4 lists the System performance requirements that the inadvertent operation must satisfy. The performance requirements listed (Parts 4.1.~~3~~4.1 – 4.1.~~3~~4.5) are the ones that are common to all planning events P0-P7 listed in TPL-001-4.

R4. Each Planning Coordinator, at least once every five full calendar years, shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Perform an evaluation of each RAS within its planning area to determine whether:

4.1.1. The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed.

4.1.2. The RAS avoids adverse interactions with other RAS, and protection and control systems.

4.1.3. For limited impact[1] RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

4.1.4. Except for limited impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following:

4.1.4.1. The BES shall remain stable.

4.1.4.2. Cascading shall not occur.

4.1.4.3. Applicable Facility Ratings shall not be exceeded.

4.1.4.4. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

4.1.4.5. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

4.1.5. Except for limited impact RAS, 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 is designed.

4.2. Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.

M4. Acceptable evidence may include, but is not limited to, dated reports or other documentation of the analyses comprising the evaluation(s) of each RAS and dated communications with the RAS-entity(ies), Transmission Planner(s), Planning Coordinator(s), and the reviewing Reliability Coordinator(s) in accordance with Requirement R4.

[1] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

Rationale for Requirement R5: The correct operation of a RAS is important for maintaining the reliability and integrity of the BES. Any incorrect operation of a RAS indicates that the RAS effectiveness and/or coordination has been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: 1) verify RAS operation was consistent with the implemented design; or 2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120 full calendar day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation. To promote reliability, each RAS-entity is required to provide the results of RAS operational performance analyses that identified any deficiencies to its reviewing RC(s).

RAS-entities may need to collaborate with their associated Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation was triggered correctly (Part 5.1.1), responded as designed (Part 5.1.2), and that the resulting BES response (Parts 5.1.3 and 5.1.4) was consistent with the intended functionality and design of the RAS. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to conduct and submit a single, coordinated operational performance analysis.

R5. Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Participate in analyzing the RAS operational performance to determine whether:

5.1.1. The System events and/or conditions appropriately triggered the RAS.

5.1.2. The RAS responded as designed.

5.1.3. The RAS was effective in mitigating BES performance issues it was designed to address.

5.1.4. The RAS operation resulted in any unintended or adverse BES response.

5.2. Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).

M5. Acceptable evidence may include, but is not limited to, dated documentation detailing the results of the RAS operational performance analysis and dated communications with participating RAS-entities and the reviewing Reliability Coordinator(s) in accordance with Requirement R5.

Rationale for Requirement R6: Deficiencies identified in the periodic RAS evaluation conducted by the PC pursuant to Requirement R4, in the operational performance analysis conducted by the RAS-entity pursuant to Requirement R5, or in the functional test performed by the RAS-entity pursuant to Requirement R8, potentially pose a reliability risk to the BES. To mitigate these potential reliability risks, Requirement R6 mandates that each RAS-entity develop a Corrective Action Plan (CAP) to address the identified deficiency. The CAP contains the mitigation actions and associated timetable necessary to remedy the specific deficiency. The RAS-entity may request assistance with CAP development from other parties such as its Transmission Planner or Planning Coordinator; however, the RAS-entity has the responsibility for compliance with this requirement.

If the CAP requires that a functional change be made to a RAS, the RAS-entity will need to submit information identified in Attachment 1 to the reviewing RC(s) prior to placing RAS modifications in~~-~~ service per Requirement R1.

Depending on the complexity of the identified deficiency(ies), development of a CAP may require studies, and other engineering or consulting work. A maximum time frame of six full calendar months is specified for RAS-entity collaboration on the CAP development. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to develop and submit a single, coordinated CAP.

R6. Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

- Being notified of a deficiency in its RAS pursuant to Requirement R4, or
- Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or
- Identifying a deficiency in its RAS pursuant to Requirement R8.

M6. Acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each reviewing Reliability Coordinator and each RAS-entity in accordance with Requirement R6.

Rationale for Requirement R7: Requirement R7 mandates each RAS-entity implement a CAP (developed in Requirement R6) that mitigates the deficiencies identified in Requirements R4, R5, or R8. By definition, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem." The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. Each reviewing Reliability Coordinator must be notified if CAP actions or timetables change, and when the CAP is completed.

R7. Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

7.1. Implement the CAP.

7.2. Update the CAP if actions or timetables change.

7.3. Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

M7. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, and communication with the reviewing Reliability Coordinator(s) that documents the implementation, updating, or completion of a CAP in accordance with Requirement R7.

Rationale for Requirement R8: Due to the wide variety of RAS designs and implementations, and the potential for impacting BES reliability, it is important that periodic functional testing of a RAS be performed. A functional test provides an overall confirmation of the RAS to operate as designed and verifies the proper operation of the non-Protection System (control) components of a RAS that are not addressed in PRC-005. Protection System components that are part of a RAS are maintained in accordance with PRC-005.

The six or twelve full calendar year test interval, which begins on the effective date of the standard pursuant to the PRC-012-2 implementation plan, is a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS. Extending to longer intervals increases the reliability risk to the BES posed by an undiscovered latent failure that could cause an incorrect operation or failure of the RAS. The RAS-entity is in the best position to determine the testing procedure and schedule due to its overall knowledge of the RAS design, installation, and functionality. Functional testing may be accomplished with end-to-end testing or a segmented approach. For segmented testing, each segment of a RAS must be tested. Overlapping segments can be tested individually negating the need for complex maintenance schedules and outages.

The maximum allowable interval between functional tests is six full calendar years for RAS that are not designated as limited impact RAS and twelve full calendar years for RAS that are designated as limited impact RAS. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. A correct operation of a RAS qualifies as a functional test for those RAS segments which operate (documentation for compliance with Requirement R5 Part 5.1). If an event causes a partial operation of a RAS, the segments without an operation will require a separate functional test within the maximum interval with the starting date determined by the previous successful test of the segments that did not operate.

R8. Each RAS-entity shall participate in performing a functional test of each of its RAS to verify the overall RAS performance and the proper operation of non-Protection System components: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

- At least once every six full calendar years for all RAS not designated as limited impact, or
- At least once every twelve full calendar years for all RAS designated as limited impact

M8. Acceptable evidence may include, but is not limited to, dated documentation detailing the RAS operational performance analysis for a correct RAS segment or an end-to-end operation (Measure M5 documentation), or dated documentation demonstrating that a functional test of each RAS segment or an end-to-end test was performed in accordance with Requirement R8.

Rationale for Requirement R9: The RAS database is a comprehensive record of all RAS existing in a Reliability Coordinator Area. The database enables the RC to provide other entities high-level information on existing RAS that could potentially impact the operational and/or planning activities of that entity. Attachment 3 lists the minimum information required for the RAS database, which includes a summary of the RAS initiating conditions, corrective actions, and System issues being mitigated. This information allows an entity to evaluate the reliability need for requesting more detailed information from the RAS-entities identified in the database contact information. The RC is the appropriate entity to maintain the database because the RC receives the required database information when a new or modified RAS is submitted for review. The twelve full calendar month time frame is aligned with industry practice and allows sufficient time for the RC to collect the appropriate information from RAS-entities and update the RAS database.

R9. Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once every twelve full calendar months. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M9. Acceptable evidence may include, but is not limited to, dated spreadsheets, database reports, or other documentation demonstrating a RAS database was updated in accordance with Requirement R9.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The RAS-entity (Transmission Owner, Generator Owner, and Distribution Provider) shall each keep data or evidence to show compliance with Requirements R1, R3, R5, R6, R7, and R8, and Measures M1, M3, M5, M6, M7, and M8 since the last audit, unless directed by its Compliance Enforcement

Authority to retain specific evidence for a longer period of time as part of an investigation.

The Reliability Coordinator shall each keep data or evidence to show compliance with Requirements R2 and R9, and Measures M2 and M9 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Planning Coordinator shall each keep data or evidence to show compliance with Requirement R4 and Measure M4 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a RAS-entity (Transmission Owner, Generator Owner or Distribution Provider), Reliability Coordinator, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The RAS-entity failed to provide the information identified in Attachment 1 to each Reliability Coordinator prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R1.
R2.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90 full calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in accordance with Requirement R2.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R3.	N/A	N/A	N/A	The RAS-entity failed to resolve identified reliability issue(s) to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in~~-~~service or retiring an existing RAS in accordance with Requirement R3.
R4.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but was late by less than or equal to 30 full calendar days.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate one of the Parts 4.1.1 through 4.1.5.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but was late by more than 90 full calendar days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate two or more of the Parts 4.1.1 through 4.1.5. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to provide the results to one or more of the receiving entities listed in Part 4.2. OR The Planning Coordinator failed to perform the evaluation in accordance with Requirement R4.
R5.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by less than or equal to 10 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address one of the Parts 5.1.1 through 5.1.4.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address two or more of the Parts 5.1.1 through 5.1.4.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to provide the results (Part 5.2) to one or more of the reviewing Reliability Coordinator(s). OR The RAS-entity failed to perform the analysis in accordance with Requirement R5.
R6.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30 full calendar days. OR The RAS-entity developed a Corrective Action Plan but failed to submit it to one or

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				more of its reviewing Reliability Coordinator(s) in accordance with Requirement R6. OR The RAS-entity failed to develop a Corrective Action Plan in accordance with Requirement R6.
R7.	The RAS-entity implemented a CAP in accordance with Requirement R7, Part 7.1, but failed to update the CAP (Part 7.2) if actions or timetables changed, or failed to notify (Part 7.3) each of the reviewing Reliability Coordinator(s) of the updated CAP or completion of the CAP.	N/A	N/A	The RAS-entity failed to implement a CAP in accordance with Requirement R7, Part 7.1.
R8.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by less than	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 30 full calendar days	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 60 full calendar days	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 90 full calendar days.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	or equal to 30 full calendar days.	but less than or equal to 60 full calendar days.	but less than or equal to 90 full calendar days.	OR The RAS-entity failed to perform the functional test for a RAS as specified in Requirement R8.
R9.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90 full calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

D. Regional Variances

None.

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by the Board of Trustees ~~Reliability Standard PRC-012-0 was adopted by the Board of Trustees.~~	
0	March 16, 2007	Identified by Commission as “fill-in-the-blank” with no action taken on the standard ~~Commission identified PRC-012-0 as a “fill-in-the-blank” standard and did not approve or remand the standard~~	
1	November 13, 2014	Adopted by the Board of Trustees ~~Revised definition of Remedial Action Scheme and several associated revised Reliability Standards, including PRC-012-1, were adopted by the Board of Trustees~~	
1	November 19, 2015	Accepted by Commission for informational purposes only ~~Commission approved revised definition of Remedial Action Scheme and accepted PRC-012-1 for informational purposes only~~	

2		Adopted by Board of Trustees~~Adopted by Board of Trustees~~	New
~~**Version**~~	~~**Date**~~	~~**Action**~~	~~**Change Tracking**~~
~~1~~		~~Adopted by NERC Board of Trustees~~	~~New~~

Attachment 1
Supporting Documentation for RAS Review

The following checklist identifies important Remedial Action Scheme (RAS) information for each new or functionally modified[2] RAS that the RAS-entity must document and provide to the reviewing Reliability Coordinator(s) (RC). If an item on this list does not apply to a specific RAS, a response of "Not Applicable" for that item is appropriate. When RAS are submitted for functional modification review and approval, only the proposed modifications to that RAS require review; however, the RAS-entity must provide a summary of the existing functionality. The RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS. Additional entities (without decision authority) may be part of the RAS review process at the request of the RC.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.
2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.
3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP.
4. Data to populate the RAS database:
   a. RAS name.
   b. Each RAS-entity and contact information.
   c. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
   d. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
   e. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
   ~~f.~~ Action(s) to be taken by the RAS.

[2] Functionally ~~M~~modified: Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

g. Identification of limited impact[3] RAS.

h. Any additional explanation relevant to high-level understanding of the RAS.

II. Functional Description and Transmission Planning Information

1. Contingencies and System conditions that the RAS is intended to remedy.
2. The action(s) to be taken by the RAS in response to disturbance conditions.
3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and the date those technical studies were performed.
4. Information regarding any future System plans that will impact the RAS.
5. RAS-entity proposal and justification for limited impact designation, if applicable.
6. Documentation describing the System performance resulting from the possible inadvertent operation of the RAS, except for limited impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be limited impact must satisfy all of the following:
   a. The BES shall remain stable.
   b. Cascading shall not occur.
   c. Applicable Facility Ratings shall not be exceeded.
   d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.
   e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.
7. An evaluation indicating that the RAS settings and operation avoid adverse interactions with other RAS, and protection and control systems.
8. Identification of other affected RCs.

[3] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

III. Implementation

1. Documentation describing the applicable equipment used for detection, dc supply, communications, transfer trip, logic processing, control actions, and monitoring.
2. Information on detection logic and settings/parameters that control the operation of the RAS.
3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in~~-~~ service or is being maintained.
4. Documentation describing the System performance resulting from a single component failure in the RAS, except for limited impact RAS, when the RAS is intended to operate. A single component failure in a RAS not determined to be limited impact must 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 is designed. The documentation should describe or illustrate how the design achieves this objective.
5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies RAS information that the RAS-entity shall document and provide to each reviewing RC.

1. Information necessary to ensure that the RC is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of applicable technical studies and technical justifications upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

Attachment 2
Reliability Coordinator RAS Review Checklist

The following checklist identifies reliability-related considerations for the Reliability Coordinator (RC) to review and verify for each new or functionally modified[4] Remedial Action Scheme (RAS). The RC review is not limited to the checklist items and the RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS. If a checklist item is not relevant to a particular RAS, it should be noted as "Not Applicable." If reliability considerations are identified during the review, the considerations and the proposed resolutions should be documented with the remaining applicable Attachment 2 items.

I. Design

1. The RAS actions satisfy performance objectives for the scope of events and conditions that the RAS is intended to mitigate.
2. The designed timing of RAS operation(s) is appropriate to its BES performance objectives.
3. The RAS arming conditions, if applicable, are appropriate to its System performance objectives.
4. The RAS avoids adverse interactions with other RAS, and protection and control systems.
5. The effects of RAS incorrect operation, including inadvertent operation and failure to operate, have been identified.
6. Determination whether or not the RAS is limited impact.[5] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.
7. Except for limited impact RAS as determined by the RC, the possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following:
   a. The BES shall remain stable.
   b. Cascading shall not occur.
   c. Applicable Facility Ratings shall not be exceeded.

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[4] Functionally ~~M~~modified: Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

[5] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

8. The effects of future BES modifications on the design and operation of the RAS have been identified, where applicable.

II. Implementation

1. The implementation of RAS logic appropriately correlates desired actions (outputs) with events and conditions (inputs).
2. Except for limited impact RAS as determined by the RC, a single component failure in a RAS does not prevent the BES from meeting the same performance requirements as those required for the events and conditions for which the RAS is designed.
3. The RAS design facilitates periodic testing and maintenance.
4. The mechanism or procedure by which the RAS is armed is clearly described, and is appropriate for reliable arming and operation of the RAS for the conditions and events for which it is designed to operate.

III. RAS Retirement

RAS retirement reviews should assure that there is adequate justification for why a RAS is no longer needed.

Attachment 3
Database Information

1. RAS name.
2. Each RAS-entity and contact information.
3. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
5. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
6. Action(s) to be taken by the RAS.
7. Identification of limited impact[6] RAS.
8. Any additional explanation relevant to high-level understanding of the RAS.

[6] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

Technical Justification

4.1.1 Reliability Coordinator

The Reliability Coordinator (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. The Wide~~-~~Area purview 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, Planning Coordinator, Transmission Planner, or other entities 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.

4.1.2 Planning Coordinator

The Planning Coordinator (PC) is the best-suited functional entity to perform the RAS evaluation 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, similar to the planning analyses performed by PCs.

4.1.3 RAS-entity

The RAS-entity is any Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If all of the RAS (RAS components) have a single owner, then that RAS-entity has sole responsibility for all the activities assigned within the standard to the RAS-entity. If the RAS (RAS components) have more than one owner, then each separate RAS component owner is a RAS-entity and is obligated to participate in various activities identified by the Requirements.

The standard does not stipulate particular compliance methods. RAS-entities have the option of collaborating to fulfill their responsibilities for each applicable requirement. Such collaboration and coordination may promote efficiency in achieving the reliability objectives of the requirements; however, the individual RAS-entity must be able to demonstrate its participation for compliance. As an example, the individual RAS-entities could collaborate to produce and submit a single, coordinated Attachment 1 to the reviewing RC pursuant to Requirement R1 to initiate the RAS review process.

Limited impact

RAS are unique and customized assemblages of protection and control equipment that vary in complexity and impact on the reliability of the BES. These differences in RAS design, action, and risk to the BES are identified and verified within the construct of Requirements R1-R4 of PRC-012-2.

The reviewing RC has the authority to designate a RAS as limited impact if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. The reviewing RC ~~is~~makes the ~~sole arbiter for determining~~final determination as to whether a RAS qualifies for the limited impact designation~~. The limited impact designation is available to any RAS in any Region~~ based upon the studies and other information provided ~~the reviewing RC determines~~with the ~~RAS poses a low risk to BES reliability~~Attachment 1 submittal by the RAS-entity.

~~The limited impact designation is modeled after~~The standard recognizes the Local Area Protection Scheme (LAPS) classification in WECC (Western Electricity Coordinating Council) and the Type ~~3~~III classification in NPCC (Northeast Power Coordinating Council~~).~~) as initially appropriate for limited impact designation. The following information describing the aforementioned WECC and NPCC RAS is excerpted from the respective regional documentation[7].The drafting team notes that the information below represents the state of the WECC and NPCC regional processes at the time of this standard development and is subject to change before the effective date of PRC-012-2.

WECC: Local Area Protection Scheme (LAPS)
A Remedial Action Scheme (RAS) whose failure to operate would NOT result in any of the following:

- Violations of TPL-001-WECC-RBP System Performance RBP,
- Maximum load loss ≥ 300 MW,
- Maximum generation loss ≥ 1000 MW.

NPCC: Type III
An SPS whose misoperation or failure to operate results in no **significant adverse impact** outside the **local area**.

The following terms are also defined by NPCC to assess the impact of the SPS for classification:

Significant adverse impact – With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from faults or disturbances, shall be deemed as having significant adverse impact:

a. system instability;
b. unacceptable system dynamic response or equipment tripping;
c. voltage levels in violation of applicable emergency limits;
d. loadings on transmission facilities in violation of applicable emergency limits;

[7] WECC Procedure to Submit a RAS for Assessment Information Required to Assess the Reliability of a RAS Guideline, Revised 10/28/2013 | NPCC Regional Reliability Reference Directory # 7, Special Protection Systems, Version 2, 3/31/2015

e. unacceptable loss of load.

Local area – An electrically confined or radial portion of the system. The geographic size and number of system elements contained will vary based on system characteristics. A local area may be relatively large geographically with relatively few buses in a sparse system, or be relatively small geographically with a relatively large number of buses in a densely networked system.

~~Because the drafting team modeled the limited impact designation after the WECC and NPCC classifications, each~~A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type ~~3~~III in NPCC, is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.

To propose an existing RAS (a RAS implemented prior to the effective date of PRC-012-2) be designated as limited impact by the reviewing RC, the RAS-entity must prepare and submit the appropriate Attachment 1 information that includes the technical justification (evaluations) documenting that the System can meet the performance requirements (specified in Requirement R4, Parts 4.1.4 and 4.1.5) resulting from a single RAS component malfunction or failure, respectively.

There is nothing that precludes a RAS-entity from working with the reviewing RC during the implementation period of PRC-012-2, in anticipation of the standard becoming enforceable. However, even if the reviewing RC determines the RAS qualifies as limited impact, the designation is not relevant until the standard becomes effective. Until then, the existing regional processes remain in effect as well as the existing RAS classifications or lack thereof.

An example of a scheme that could be recognized as a limited impact RAS is a load shedding or generation rejection scheme used to mitigate the overload of a BES transmission line. The inadvertent operation of such a scheme would cause the loss of either a certain amount of generation or load. The evaluation by the RAS-entity should demonstrate that the loss of this amount of generation or load, without the associated contingency for RAS operation actually occurring, is acceptable and not detrimental to the reliability of BES; e.g., in terms of frequency and voltage stability. The failure of that scheme to operate when intended could potentially lead to the overloading of a transmission line beyond its acceptable rating. The RAS-entity would need to demonstrate that this overload, while in excess of the applicable Facility Rating, is not detrimental to the BES outside the contained area (predetermined by studies) affected by the contingency.

~~Another example~~Other examples of ~~a~~ limited~~-~~ impact RAS ~~is a~~include:

- A scheme used to protect BES equipment from damage caused by overvoltage through generation rejection or equipment tripping.

- ~~Another example of a limited-impact RAS is a~~A centrally-controlled undervoltage load shedding scheme used to protect a contained area (predetermined by studies) of the BES against voltage collapse.
- A scheme used to trip a generating unit following certain BES Contingencies to prevent the unit from going out of synch with the System; where, if the RAS fails to operate and the unit pulls out of synchronism, the resulting apparent impedance swings do not result in the tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities.

Requirement R1

Each RAS is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES); therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification, or retirement (removal from service) must be completed prior to implementation.

Functional modifications consists of any of the following:

- Changes to System conditions or Contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

An example indicating the limits of an in-kind replacement of a RAS component is the replacement of one relay (or other device) with a relay (or other device) that uses similar functions. For instance, if a RAS included a CO-11 relay which was replaced by an IAC-53 relay, that would be an in-kind replacement. If the CO-11 relay were replaced by a microprocessor SEL-451 relay that used only the same functions as the original CO-11 relay, that would also be an in-kind replacement; however, if the SEL-451 relay was used to add new logic to what the CO-11 relay had provided, then the replacement relay would be a functional modification.

Changes to RAS pickup levels that require no other scheme changes are not considered a functional modification. For example, System conditions require a RAS to be armed when the combined flow on two lines exceeds 500 MW. If a periodic evaluation pursuant to Requirement R4, or other assessment, indicates that the arming level should be reduced to 450 MW without requiring any other RAS changes that would not be a functional modification. Similarly, if a RAS is designed to shed load to reduce loading on a particular line below 1000 amps, then a change in the load shedding trigger from 1000 amps to 1100 amps would not be a functional modification.

Another example illustrates a case where a System change may result in a RAS functional change. Assume that a generation center is connected to a load center through two transmission lines. The lines are not rated to accommodate full plant output if one line is out of service, so a RAS monitors the status of both lines and trips or ramps down the generation to a safe level following loss of either line. Later, one of the lines is tapped to serve additional load. The System that the RAS impacts now includes three lines, loss of any of which is likely to still require generation reduction. The modified RAS will need to monitor all three lines (add two line terminal status inputs to the RAS) and the logic to recognize the specific line outages would change, while the generation reduction (RAS output) requirement may or may not change, depending on which line is out of service. These required RAS changes would be a functional modification.

Any functional modification to a RAS will need to be reviewed and approved through the process described in Requirements R1, R2, and R3. The need for such functional modifications may be identified in several ways including but not limited to the Planning evaluations pursuant to R4, incorrect operations pursuant to R5, a test failure pursuant to R8, or Planning assessments related to future additions or modifications of other facilities.

See Item 4a in the Implementation Section of Attachment 1 in the Supplemental Material section for typical RAS components for which a failure may be considered. The RC has the discretion to make the final determination regarding which components should be regarded as RAS components during its review.

To facilitate a review that promotes reliability, the RAS-entity(ies) must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity(ies) provide them to the reviewing Reliability Coordinator (RC). The RC that coordinates the area where the RAS is located is responsible for the review. In cases where a RAS crosses multiple RC Area boundaries, each affected RC is responsible for conducting either individual reviews or a coordinated review.

Requirement R1 does not specify how far in advance of implementation the RAS-entity(ies) must provide Attachment 1 data to the reviewing RC. The information will need to be submitted early enough to allow RC review in the allotted time pursuant to Requirement R2, including resolution of any reliability issues that might be identified, in order to obtain approval of the reviewing RC. Expeditious submittal of this information is in the interest of each RAS-entity to effect a timely implementation.

Requirement R2

Requirement R2 mandates that the RC perform reviews of all proposed new RAS and existing RAS proposed for functional modification, or retirement (removal from service) in its RC Area.

RAS are unique and customized assemblages of protection and control equipment. As such, they have a potential to introduce reliability risks to the BES, if not carefully planned, designed, and installed. A RAS may be installed to address a reliability issue, or achieve an economic or operational advantage, and could introduce reliability risks that might not be apparent to a RAS-entity(ies). An independent review by a multi-disciplinary panel of subject matter experts with planning, operations, protection, telecommunications, and equipment expertise is an effective means of identifying risks and recommending RAS modifications when necessary.

The RC is the functional entity best suited to perform the RAS reviews because it has the widest~~-~~ area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. This Wide Area purview facilitates the evaluation of interactions among separate RAS as well as interactions among the 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, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC may request assistance in RAS reviews from other parties such as the PC(s) or regional technical groups (e.g., Regional Entities); however, the RC retains responsibility for compliance with the requirement. It is recognized that the RC does not possesses more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not contain compliance requirements. If Reliability Standards address functions that are not described in the model, the Reliability Standard requirements take precedence over the Functional Model. For further reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009. Attachment 2 of this standard is a checklist for assisting the RC in identifying design and implementation aspects of a RAS, and for facilitating consistent reviews of each RAS submitted for review. The time frame of four full calendar months is consistent with current utility practice; however, flexibility is provided by allowing the parties to negotiate a different schedule for the review. Note, an RC may need to include this task in its reliability plan(s) for the NERC Region(s) in which it is located.

Requirement R3

Requirement R3 mandates that each RAS-entity resolve all reliability issues (pertaining to its RAS) identified during the RAS review by the reviewing Reliability Coordinators. Examples of reliability issues include a lack of dependability, security, or coordination. RC approval of a RAS is considered to be obtained when the reviewing RC's feedback to each RAS-entity indicates that either no reliability issues were identified during the review or all identified reliability issues were resolved to the RC's satisfaction.

Dependability is a component of reliability that is the measure of certainty of a device to operate when required. If a RAS is installed to meet performance requirements of NERC Reliability Standards, a failure of the RAS to operate when intended would put the System at risk of violating NERC Reliability Standards if specified Contingency(ies) or System conditions occur. This risk is mitigated by designing the RAS so that it will accomplish the intended purpose while experiencing a single RAS component failure. This is often accomplished through redundancy. Other strategies for providing dependability include "over-tripping" load or generation, or alternative automatic backup schemes.

Security is a component of reliability that is the measure of certainty of a device to not operate inadvertently. False or inadvertent operation of a RAS results in taking a programmed action without the appropriate arming conditions, occurrence of specified Contingency(ies), or System conditions expected to trigger the RAS action. Typical RAS actions include shedding load or generation or re-configuring the System. Such actions, if inadvertently taken, are undesirable and may put the System in a less secure state. Worst case impacts from inadvertent operation often occur if all programmed RAS actions occur. If the System performance still satisfies PRC-012-2 Requirement R4, Part 4.3, no additional mitigation is required. Security enhancements to the RAS design, such as voting schemes, are acceptable mitigations against inadvertent operations.

Any reliability issue identified during the review must be resolved before implementing the RAS to avoid placing the System at unacceptable risk. The RAS-entity or the reviewing RC(s) may have alternative ideas or methods available to resolve the issue(s). In either case, the concern needs to be resolved in deference to reliability, and the RC has the final decision.

A specific time period for the RAS-entity to respond to the RC(s) review is not necessary because an expeditious response is in the interest of each RAS-entity to effect a timely implementation.

A specific time period for the RC to respond to the RAS-entity following the RAS review is also not necessary because the RC will be aware of (1) any reliability issues associated with the RAS not being in service and (2) the RAS-entity's schedule to implement the RAS to address those reliability issues. Since the RC is the ultimate arbiter of BES operating reliability, resolving reliability issues is a priority for the RC and serves as an incentive to expeditiously respond to the RAS-entity.

Requirement R4

Requirement R4 mandates that an evaluation of each RAS be performed at least once every five full calendar years. The purpose of a periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that requirements for BES performance following inadvertent RAS operation and single component failure continue to be satisfied. A periodic evaluation is required because changes in System topology or operating conditions may change the effectiveness of a RAS or the way it interacts with and impacts the BES.

A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. Limited impact RAS are not subject to the RAS single component malfunction and failure tests of Parts 4.1.4 and 4.1.5, respectively. Requiring a limited impact RAS to meet these tests would add complexity to the design with minimal benefit to BES reliability.

A RAS implemented after the effective date of this standard can only be designated as limited impact by the reviewing RC(s). A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type ~~3~~III in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.
Requirement R4 also clarifies that the RAS single component failure and inadvertent operation tests do not apply to RAS which are determined to be limited impact. Requiring a limited impact RAS to meet the single component failure and inadvertent operation tests would just add complexity to the design with little or no improvement in the reliability of the BES.

For existing RAS, the initial performance of Requirement R4 must be completed within five full calendar years of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within five full calendar years of the RAS approval date by the reviewing RC(s). Five full calendar years was selected as the maximum time frame between evaluations based on the time frames for similar requirements in Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation can be performed sooner if it is determined that material changes to System topology or System operating conditions could potentially impact the effectiveness or coordination of the RAS. System changes also have the potential to alter the reliability impact of limited impact RAS on the BES. Requirement 4, Part 4.1.3 explicitly requires the periodic evaluation of limited impact RAS to verify the limited impact designation remains applicable. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluations (Requirement R4, Parts 4.1.1 through 4.1.5) are planning analyses that may involve modeling of the interconnected transmission system to assess BES performance. The PC is the functional entity best suited to perform the analyses because they have a wide-area planning perspective. To promote reliability, the PC is required to provide the results of the evaluation to each impacted Transmission Planner and Planning Coordinator, in addition to each reviewing RC and RAS-entity. In cases where a RAS crosses PC boundaries, each affected PC is responsible for conducting either individual evaluations or participating in a coordinated evaluation.

The intent of Requirement R4, Part 4.1.4 is to ~~require~~verify that the possible inadvertent operation of the RAS (other than limited impact RAS), caused by the malfunction of a single component of the RAS, meet the same System performance requirements as those required for the Contingency(ies) or System conditions for which it is designed. If the RAS is designed to meet one of the planning events (P0-P7) in TPL-001-4, the possible inadvertent operation of the

RAS must meet the same performance requirements listed in the standard for that planning event. The requirement clarifies that the inadvertent operation to be considered is only that caused by the malfunction of a single RAS component. This allows features to be designed into the RAS to improve security, such that inadvertent operation due to malfunction of a single component is prevented; otherwise, the RAS inadvertent operation must satisfy Requirement R4, Part 4.1.4.

The intent of Requirement R4, Part 4.1.4 is also to ~~require~~verify that the possible inadvertent operation of the RAS (other than limited impact RAS) installed for an extreme event in TPL-001-4 or for some other Contingency or System conditions not defined in TPL-001-4 (therefore without performance requirements), meet the minimum System performance requirements of Category P7 in Table 1 of NERC Reliability Standard TPL-001-4. However, instead of referring to the TPL standard, the requirement lists the System performance requirements that a potential inadvertent operation must satisfy. The performance requirements listed (Requirement R4, Parts 4.1.4.1 – 4.1.4.5) are the ones that are common to all planning events (P0-P7) listed in TPL-001-4.

With reference to Requirement 4, Part 4.1.4, note that the only differences in performance requirements among the TPL (P0-P7) events (not common to all of them) concern Non-Consequential Load Loss and interruption of Firm Transmission Service. It is not necessary for Requirement R4, Part 4.1.4 to specify performance requirements related to these areas because a RAS is only allowed to drop non-consequential load or interrupt Firm Transmission Service if that action is allowed for the Contingency for which it is designed. Therefore, the inadvertent operation should automatically meet Non-Consequential Load Loss or interrupting Firm Transmission Service performance requirements for the Contingency(ies) for which it was designed.

The intent of Requirement R4, Part 4.1.5 ~~requires~~is to verify that a single component failure in ~~the~~a RAS ~~(~~, other than limited impact 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 is designed. This analysis is needed to ensure that changing System conditions do not result in the single component failure requirement not being met.

The following is an example of a single component failure causing the System to fail to meet the performance requirements for the P1 event for which the RAS was installed. ~~Requirements for inadvertent RAS operation (Requirement R4, Part 4.1.4) and single component failure (Requirement R4, Part 4.1.5) are reviewed by the reviewing RC(s) before a new or functionally modified RAS is placed in-service, and are typically satisfied by specific design considerations. Although the scope of the periodic evaluation does not include a new design review, it is possible that a~~Consider the instance where a three-phase Fault (P1 event) results in a generating plant becoming unstable (a violation of the System performance requirements of TPL-001-4). To resolve this, a RAS is installed to trip a single generating unit which allows the remaining units at the plant to remain stable. If failure of a single component (e.g., relay) in the

RAS results in the RAS failing to operate for the P1 event, the generating plant would become unstable (failing to meet the System performance requirements of TPL-001-4 for a P1 event).

Requirement R4, Part 4.1.5 does not mandate that all RAS have redundant components. For example:

- Consider the instance where a RAS is installed to mitigate an extreme event in TPL-001-4. There are no System performance requirements for extreme events; therefore, the RAS does not need redundancy to meet the same performance requirements as those required for the events and conditions for which the RAS was designed.

- Consider a RAS that arms more load or generation than necessary such that failure of the RAS to drop a portion of load or generation due to that single component failure will still result in satisfactory System performance, as long as tripping the total armed amount of load or generation does not cause other adverse impacts to reliability.

The scope of the periodic evaluation does not include a new review of the physical implementation of the RAS, as this was confirmed by the RC during the initial review and verified by subsequent functional testing. However, it is possible that a RAS design which previously satisfied requirements for inadvertent RAS operation and single component failure by means other than component redundancy may fail to satisfy these requirements at a later time, and must be evaluated with respect to the current System. For example, if the actions of a particular RAS include tripping load, load growth could occur over time that impacts the amount of load to be tripped. These changes could result in tripping too much load upon inadvertent operation and result in violations of Facility Ratings. Alternatively, the RAS might be designed to trip more load than necessary (i.e., "over trip") in order to satisfy single component failure requirements. System changes could result in too little load being tripped and unacceptable BES performance if one of the loads failed to trip.

Requirement R5

The correct operation of a RAS is important to maintain the reliability and integrity of the BES. Any incorrect operation of a RAS indicates the RAS effectiveness and/or coordination may have been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: (1) verify RAS operation is consistent with implemented design; or (2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120 full calendar day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation; however, flexibility is provided by allowing the parties to negotiate a different schedule for the analysis. To promote reliability, the RAS-entity(s) is required to provide the results of RAS operational performance analyses to its reviewing RC(s) if the analyses revealed a deficiency.

The RAS-entity(ies) may need to collaborate with its associated Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation was triggered correctly (Part 5.1.1), responded as designed (Part 5.1.2), and that the resulting BES response (Parts 5.1.3 and 5.1.4) was consistent with the intended functionality and design of the RAS. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to conduct and submit a single, coordinated operational performance analysis.

Requirement R6

RAS deficiencies potentially pose a reliability risk to the BES. RAS deficiencies may be identified in the periodic RAS evaluation conducted by the PC in Requirement R4, in the operational analysis conducted by the RAS-entity in Requirement R5, or in the functional test performed by the RAS-entity(ies) in Requirement R8. To mitigate potential reliability risks, Requirement R6 mandates that each RAS-entity participate in developing a CAP that establishes the mitigation actions and timetable necessary to address the deficiency.

The RAS-entity(ies) that owns the RAS components, is responsible for the RAS equipment, and is in the best position to develop the timelines and perform the necessary work to correct RAS deficiencies. If necessary, the RAS-entity(ies) may request assistance with development of the CAP from other parties such as its Transmission Planner or Planning Coordinator; however, the RAS-entity has the responsibility for compliance with this requirement.

A CAP may require functional changes be made to a RAS. In this case, Attachment 1 information must be submitted to the reviewing RC(s), an RC review must be performed to obtain RC approval before the RAS-entity can place RAS modifications in~~-~~ service, per Requirements R1, R2, and R3.

Depending on the complexity of the issues, development of a CAP may require study, engineering or consulting work. A timeframe of six full calendar months is allotted to allow enough time for RAS-entity collaboration on the CAP development, while ensuring that deficiencies are addressed in a reasonable time. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to develop and submit a single, coordinated CAP. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the RAS deficiency is resolved. The possibility of such operating restrictions will incent the RAS-entity to resolve the issue as quickly as possible.

The following are example situations of when a CAP is required:

- A determination after a RAS operation/non-operation investigation that the RAS did not meet performance expectations or did not operate as designed.

- Periodic planning assessment reveals RAS changes are necessary to correct performance or coordination issues.
- Equipment failures.
- Functional testing identifies that a RAS is not operating as designed.

Requirement R7

Requirement R7 mandates that each RAS-entity implement its CAP developed in Requirement R6 which mitigates the deficiencies identified in Requirements R4, R5, or R8. By definition, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem."

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. If the CAP is changed, the RAS-entity must notify the reviewing Reliability Coordinator(s). The RAS-entity must also notify the Reliability Coordinator(s) when the CAP has been completed.

The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions will incent the RAS-entity to complete the CAP as quickly as possible.

Requirement R8

The reliability objective of Requirement R8 is to test the non-Protection System components of a RAS (controllers such as programmable logic controllers (PLCs)) and to verify the overall performance of the RAS through functional testing. Functional tests validate RAS operation by ensuring System states are detected and processed, and that actions taken by the controls are correct and occur within the expected time using the in-service settings and logic. Functional testing is aimed at assuring overall RAS performance and not the component focused testing contained in the PRC-005 maintenance standard.

Since the functional test operates the RAS under controlled conditions with known System states and expected results, testing and analysis can be performed with minimum impact to the BES and should align with expected results. The RAS-entity is in the best position to determine the testing procedure and schedule due to their overall knowledge of the RAS design, installation, and functionality. Periodic testing provides the RAS-entity assurance that latent failures may be identified and also promotes identification of changes in the System that may have introduced latent failures.

The six and twelve full calendar year functional testing intervals are greater than the annual or bi-annual periodic testing performed in some NERC Regions. However, these intervals are a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS. Longer test intervals for limited impact RAS are acceptable because incorrect operations or failures to operate present a low reliability risk to the Bulk Power System.

Functional testing is not synonymous with end-to-end testing. End-to-end testing is an acceptable method but may not be feasible for many RAS. When end-to-end testing is not possible, a RAS-entity may use a segmented functional testing approach. The segments can be tested individually negating the need for complex maintenance schedules. In addition, actual RAS operation(s) can be used to fulfill the functional testing requirement. If a RAS does not operate in its entirety during a System event or System conditions do not allow an end-to-end scheme test, then the segmented approach should be used to fulfill this Requirement. Functional testing includes the testing of all RAS inputs used for detection, arming, operating, and data collection. Functional testing, by default operates the processing logic and infrastructure of a RAS, but focuses on the RAS inputs as well as the actions initiated by RAS outputs to address the System condition(s) for which the RAS is designed. All segments and components of a RAS must be tested or have proven operations within the applicable maximum test interval to demonstrate compliance with the Requirement.

As an example of segment testing, consider a RAS controller implemented using a PLC that receives System data, such as loading or line status, from distributed devices. These distributed devices could include meters, protective relays, or other PLCs. In this example RAS, a line protective relay is used to provide an analog metering quantity to the RAS control PLC. A functional test would verify that the System data is received from the protective relay by the PLC, processed by the PLC, and that PLC outputs are appropriate. There is no need to verify the protective relay's ability to measure the power system quantities, as this is a requirement for Protection Systems used as RAS in PRC-005, Table 1-1, Component Type – Protective Relay. Rather the functional test is focused on the use of the protective relay data at the PLC, including the communications data path from relay to PLC if this data is essential for proper RAS operation. Additionally, if the control signal back to the protective relay is also critical to the proper functioning of this example RAS, then that path is also verified up~~-~~ to the protective relay. This example describes a test for one segment of a RAS which verifies RAS action, verifies PLC control logic, and verifies RAS communications.

IEEE C37.233, "IEEE Guide for Power System Protection Testing," 2009 section 8 (particularly 8.3-8.5), provides an overview of functional testing. The following opens section 8.3:

> Proper implementation requires a well-defined and coordinated test plan for performance evaluation of the overall system during agreed maintenance intervals. The maintenance test plan, also referred to as functional system testing, should include inputs, outputs, communication, logic, and throughput timing tests. The functional tests are generally not component-level testing, rather overall system testing. Some of the input tests may need to be done ahead of overall system testing to the extent that the tests affect the overall performance. The test coordinator or coordinators need to have full knowledge of the intent of the scheme, isolation points, simulation scenarios, and restoration to normal procedures.

> The concept is to validate the overall performance of the scheme, including the logic where applicable, to validate the overall throughput times against system modeling for different types of Contingencies, and to verify scheme performance as well as the inputs and outputs.

If a RAS passes a functional test, it is not necessary to provide that specific information to the RC because that is the expected result and requires no further action. If a segment of a RAS fails a functional test, the status of that degraded RAS is required to be reported (in Real-time) to the Transmission Operator via PRC-001, Requirement R6, then to the RC via TOP-001-3, Requirement R8. See Phase 2 of Project 2007-06 for the mapping document from PRC-001 to other standards regarding notification of RC by TOP if a deficiency is found during testing. Consequently, it is not necessary to include a similar requirement in this standard.

The initial test interval begins on the effective date of the standard pursuant to the implementation plan. Subsequently, the maximum allowable interval between functional tests is six full calendar years for RAS that are not designated as limited impact RAS and twelve full calendar years for RAS that are designated as limited impact RAS. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. A RAS-entity may choose to count a correct RAS operation as a qualifying functional test for those RAS segments which operate. If a System event causes a correct, but partial RAS operation, separate functional tests of the segments that did not operate are still required within the maximum test interval that started on the date of the previous successful test of those (non-operating) segments in order to be compliant with Requirement R8.

Requirement R9

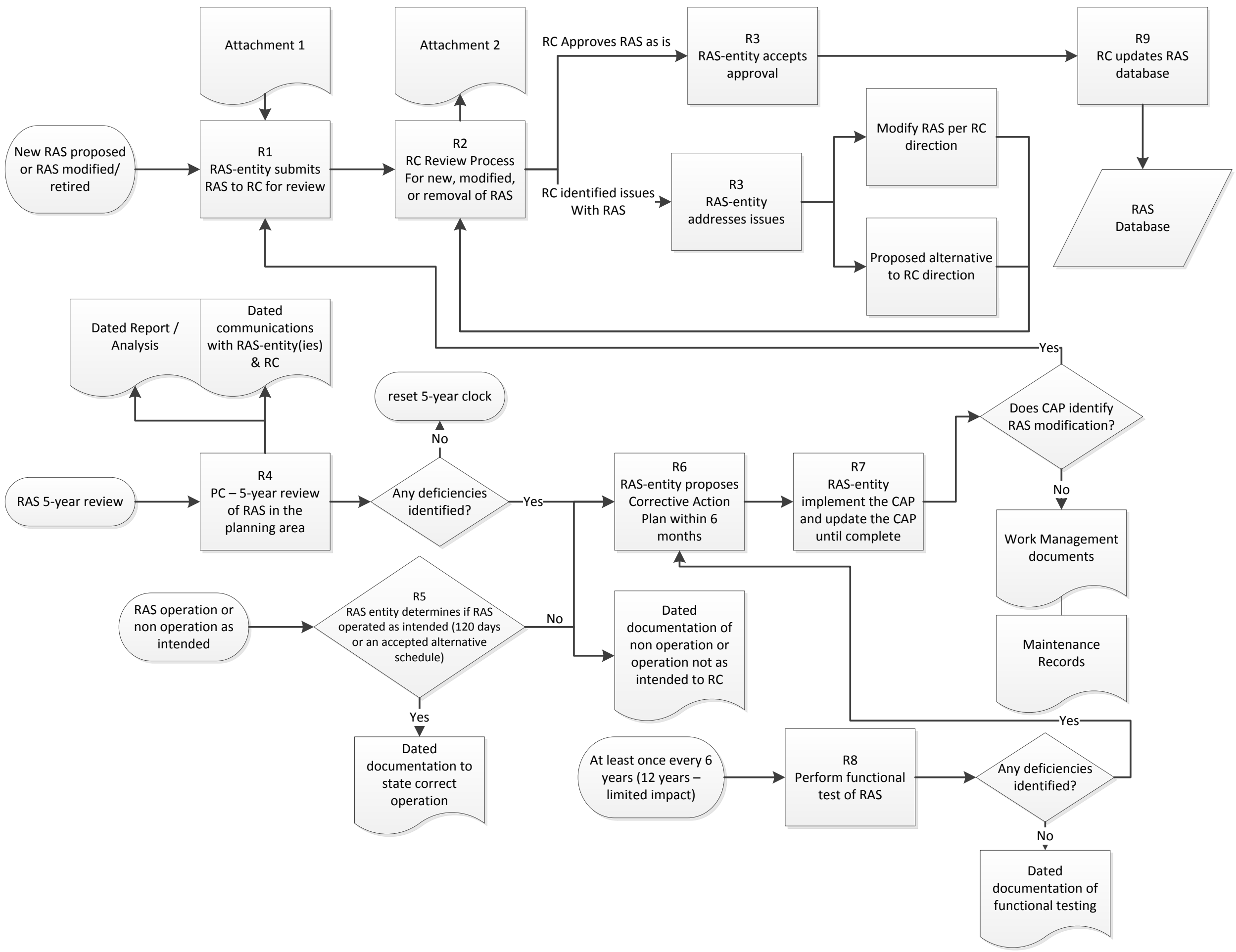
The RAS database required to be maintained by the RC in Requirement R9 ensures information regarding existing RAS is available. Attachment 3 contains the minimum information that is required to be included about each RAS listed in the database. Additional information can be requested by the RC.

The database enables the RC to provide other entities high-level information on existing RAS that could potentially impact the operational and/or planning activities of that entity. The information provided is sufficient for an entity with a reliability need to evaluate whether the RAS can impact its System. For example, a RAS performing generation rejection to mitigate an overload on a transmission line may cause a power flow change within an adjacent entity area. This entity should be able to evaluate the risk that a RAS poses to its System from the high-level information provided in the RAS database.

The RAS database does not need to list detailed settings or modeling information, but the description of the System performance issues, System conditions, and the intended corrective actions must be included. If additional details about the RAS operation are required, the entity may obtain the contact information of the RAS-entity from the RC.

Process Flow Diagram

The diagram below depicts the process flow of the PRC-012-2 requirements.



Technical Justifications for Attachment 1 Content
Supporting Documentation for RAS Review

To perform an adequate review of the expected reliability implications of a Remedial Action Scheme (RAS), it is necessary for the RAS-entity(ies) to provide a detailed list of information describing the RAS to the reviewing RC. If there are multiple RAS-entities for a single RAS, information will be needed from all RAS-entities. Ideally, in such cases, a single RAS-entity will take the lead to compile all the data identified into a single Attachment 1.

The necessary data ranges from a general overview of the RAS to summarized results of transmission planning studies, to information about hardware used to implement the RAS. Coordination between the RAS and other RAS and protection and control systems will be examined for possible adverse interactions. This review can include wide-ranging electrical design issues involving the specific hardware, logic, telecommunications, and other relevant equipment and controls that make up the RAS.

Attachment 1

The following checklist identifies important RAS information for each new or functionally modified[8] RAS that the RAS-entity shall document and provide to the RC for review pursuant to Requirement R1. When a RAS has been previously reviewed, only the proposed modifications to that RAS require review; however, it will be helpful to each reviewing RC if the RAS-entity provides a summary of the existing RAS functionality.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.

   Provide a description of the RAS to give an overall understanding of the functionality and a map showing the location of the RAS. Identify other protection and control systems requiring coordination with the RAS. See RAS Design below for additional information.

   Provide a single-line drawing(s) showing all sites involved. The drawing(s) should provide sufficient information to allow the RC review team to assess design reliability, and should include information such as the bus arrangement, circuit breakers, the associated switches, etc. For each site, indicate whether detection, logic, action, or a combination of these is present.

2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.

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[8] Functionally ~~M~~modified: Any modification to a RAS consisting of any of the following:

- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP. [Reference NERC Reliability Standard PRC-012-2, Requirements R5 and R7]

   Provide a description of any functional modifications to a RAS that are part of a CAP that are proposed to address performance deficiency(ies) identified in the periodic evaluation pursuant to Requirement R4, the analysis of an actual RAS operation pursuant to Requirement R5, or functional test failure pursuant to Requirement R8. A copy of the most recent CAP must be submitted in addition to the other data specified in Attachment 1.

4. Initial data to populate the RAS database.

   a. RAS name.

   b. Each RAS-entity and contact information.

   c. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent five full calendar year (Requirement R4) evaluation date; and, date of retirement, if applicable.

   d. System performance issue or reason for installing the RAS (*e.g.*, thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery).

   e. Description of the Contingencies or System conditions for which the RAS was designed (initiating conditions).

   f. Corrective action taken by the RAS.

   g. Identification of limited impact[9] RAS.

   h. Any additional explanation relevant to high level understanding of the RAS.

      Note: This is the same information as is identified in Attachment 3. Supplying the data at this point in the review process ensures a more complete review and minimizes any administrative burden on the reviewing RC(s).

II. Functional Description and Transmission Planning Information

1. Contingencies and System conditions that the RAS is intended to remedy. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.1]

   a. The System conditions that would result if no RAS action occurred should be identified.

   b. Include a description of the System conditions that should arm the RAS so as to be ready to take action upon subsequent occurrence of the critical System Contingencies or other operating conditions when RAS action is intended to occur. If no arming conditions are required, this should also be stated.

[9] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

c. Event-based RAS are triggered by specific Contingencies that initiate mitigating action. Condition-based RAS may also be initiated by specific Contingencies, but specific Contingencies are not always required. These triggering Contingencies and/or conditions should be identified.

2. The actions to be taken by the RAS in response to disturbance conditions. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.2]

   Mitigating actions are designed to result in acceptable System performance. These actions should be identified, including any time constraints and/or "backup" mitigating measures that may be required in case of a single RAS component failure.

3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and the date those technical studies were performed. [Reference NEC Reliability Standard PRC-014, R3.2]

   Review the scheme purpose and impact to ensure it is (still) necessary, serves the intended purposes, and meets current performance requirements. While copies of the full, detailed studies may not be necessary, any abbreviated descriptions of the studies must be detailed enough to allow the reviewing RC(s) to be convinced of the need for the scheme and the results of RAS-related operations.

4. Information regarding any future System plans that will impact the RAS. [Reference NERC Reliability Standard PRC-014, R3.2]

   The RC's other responsibilities under the NERC Reliability Standards focus on the Operating Horizon, rather than the Planning Horizon. As such, the RC is less likely to be aware of any longer range plans that may have an impact on the proposed RAS. Such knowledge of future Plans is helpful to provide perspective on the capabilities of the RAS.

5. RAS-entity proposal and justification for limited impact designation, if applicable.

   A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type 3 in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.

6. Documentation describing the System performance resulting from the possible inadvertent operation of the RAS, except for limited impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be limited impact must satisfy all of the following: [Reference NERC Reliability Standard PRC-012, R1.4]

a. The BES shall remain stable.

b. Cascading shall not occur.

c. Applicable Facility Ratings shall not be exceeded.

d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

7. An evaluation indicating that the RAS settings and operation avoids adverse interactions with other RAS, and protection and control systems.
[Reference NERC Reliability Standards PRC-012, R1.5 and PRC-014, R3.4]

   RAS are complex schemes that may take action such as tripping load or generation or re-configuring the System. Many RAS depend on sensing specific System configurations to determine whether they need to arm or take actions. An examples of an adverse interaction: A RAS that reconfigures the System also changes the available ~~fault~~ Fault duty, which can affect distance relay overcurrent ("fault detector") supervision and ground overcurrent protection coordination.

8. Identification of other affected RCs.

   This information is needed to aid in information exchange among all affected entities and coordination of the RAS with other RAS and protection and control systems.

III. Implementation

1. Documentation describing the applicable equipment used for detection, dc supply, communications, transfer trip, logic processing, control actions, and monitoring.

   Detection
   Detection and initiating devices, whether for arming or triggering action, should be designed to be secure. Several types of devices have been commonly used as disturbance, condition, or status detectors:

   - Line open status (event detectors),
   - Protective relay inputs and outputs (event and parameter detectors),
   - Transducer and IED (analog) inputs (parameter and response detectors),
   - Rate of change (parameter and response detectors).

   DC Supply
   Batteries and charges, or other forms of dc supply for RAS, are commonly also used for Protection Systems. This is acceptable, and maintenance of such supplies is covered by PRC-005. However, redundant RAS ~~systems~~, when used, should be supplied from separately protected (fused or breakered) circuits.

Communications: Telecommunications Channels

Telecommunications channels used for sending and receiving RAS information between sites and/or transfer trip devices should meet at least the same criteria as other relaying protection communication channels. Discuss performance of any non-deterministic communication systems used (such as Ethernet).

The scheme logic should be designed so that loss of the channel, noise, or other channel or equipment failure will not result in a false operation of the scheme.

It is highly desirable that the channel equipment and communications media (power line carrier, microwave, optical fiber, etc.) be owned and maintained by the RAS-entity, or perhaps leased from another entity familiar with the necessary reliability requirements. All channel equipment should be monitored and alarmed to the dispatch center so that timely diagnostic and repair action shall take place upon failure. Publicly switched telephone networks are generally an undesirable option.

Communication channels should be well labeled or identified so that the personnel working on the channel can readily identify the proper circuit. Channels between entities should be identified with a common name at all terminals.

Transfer Trip

Transfer trip equipment, when separate from other RAS equipment, should be monitored and labeled similarly to the channel equipment.

Logic Processing

All RAS require some form of logic processing to determine the action to take when the scheme is triggered. Required actions are always scheme dependent. Different actions may be required at different arming levels or for different Contingencies. Scheme logic may be achievable by something as simple as wiring a few auxiliary relay contacts or by much more complex logic processing.

Platforms that have been used reliably and successfully include PLCs in various forms, personal computers (PCs), microprocessor protective relays, remote terminal units (RTUs), and logic processors. Single-function relays have been used historically to implement RAS, but this approach is now less common except for very simple new RAS or minor additions to existing RAS.

Control Actions

RAS action devices may include a variety of equipment such as transfer trip, protective relays, and other control devices. These devices receive commands from the logic processing function (perhaps through telecommunication facilities) and initiate RAS actions at the sites where action is required.

Monitoring by SCADA/EMS should include at least

- Whether the scheme is in~~-~~ service or out of service.
  - For RAS that are armed manually, the arming status may be the same as whether the RAS is in~~-~~ service or out of service.

    - For RAS that are armed automatically, these two states are independent because a RAS that has been placed in~~-~~ service may be armed or unarmed based on whether the automatic arming criteria have been met.
- The current operational state of the scheme (available or not).
- In cases where the RAS requires single component failure performance; e.g., redundancy, the minimal status indications should be provided separately for each RAS~~system~~.
    - The minimum status is generally sufficient for operational purposes; however, where possible it is often useful to provide additional information regarding partial failures or the status of critical components to allow the RAS-entity to more efficiently troubleshoot a reported failure. Whether this capability exists will depend in part on the design and vintage of equipment used in the RAS. While all schemes should provide the minimum level of monitoring, new schemes should be designed with the objective of providing monitoring at least similar to what is provided for microprocessor-based Protection Systems.

2. Information on detection logic and settings/parameters that control the operation of the RAS. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.3]

   Several methods to determine line or other equipment status are in common use, often in combination:

   a. Auxiliary switch contacts from circuit breakers and disconnect switches (52a/b, 89a/b)—the most common status monitor; “a” contacts exactly emulate actual breaker status, while “b” contacts are opposite to the status of the breaker;

   b. Undercurrent detection—a low level indicates an open condition, including at the far end of a line; pickup is typically slightly above the total line-charging current;

   c. Breaker trip coil current monitoring—typically used when high-speed RAS response is required, but usually in combination with auxiliary switch contacts and/or other detection because the trip coil current ceases when the breaker opens; and

   d. Other detectors such as angle, voltage, power, frequency, rate of change of the aforementioned, out of step, etc. are dependent on specific scheme requirements, but some forms may substitute for or enhance other monitoring described in items ‘a’, ‘b’, and ‘c’ above.

   Both RAS arming and action triggers often require monitoring of analog quantities such as power, current, and voltage at one or more locations and are set to detect a specific level of the pertinent quantity. These monitors may be relays, meters, transducers, or other devices

3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in~~-~~ service or is being maintained.

In this context, a multifunction device (e.g., microprocessor-based relay) is a single component that is used to perform the function of a RAS in addition to protective relaying and/or SCADA simultaneously. It is important that other applications in the multifunction device do not compromise the functionality of the RAS when the device is in service or when it is being maintained. The following list outlines considerations when the RAS function is applied in the same microprocessor-based relay as equipment protection functions:

a. Describe how the multifunction device is applied in the RAS.

b. Show the general arrangement and describe how the multi-function device is labeled in the design and application, so as to identify the RAS and other device functions.

c. Describe the procedures used to isolate the RAS function from other functions in the device.

d. Describe the procedures used when each multifunction device is removed from service and whether coordination with other protection schemes is required.

e. Describe how each multifunction device is tested, both for commissioning and during periodic maintenance testing, with regard to each function of the device.

f. Describe how overall periodic RAS functional and throughput tests are performed if multifunction devices are used for both local protection and RAS.

g. Describe how upgrades to the multifunction device, such as firmware upgrades, are accomplished. How is the RAS function taken into consideration?

Other devices that are usually not considered multifunction devices such as auxiliary relays, control switches, and instrument transformers may serve multiple purposes such as protection and RAS. Similar concerns apply for these applications as noted above.

4. Documentation describing the System performance resulting from a single component failure in the RAS, except for limited impact RAS, when the RAS is intended to operate. A single component failure in a RAS not determined to be limited impact must 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 is designed. The documentation should describe or illustrate how the design achieves this objective. [Reference NERC Reliability Standard PRC-012, R1.3]

   RAS automatic arming, if applicable, is vital to RAS and System performance and is therefore included in this requirement.

   Acceptable methods to achieve this objective include, but are not limited to the following:

   a. Providing redundancy of RAS components. Typical examples are listed below:

      i. Protective or auxiliary relays used by the RAS.

ii. Communications systems necessary for correct operation of the RAS.

iii. Sensing devices used to measure electrical or other quantities used by the RAS.

iv. Station dc supply associated with RAS functions.

v. Control circuitry associated with RAS functions through the trip coil(s) of the circuit breakers or other interrupting devices.

vi. Logic processing devices that accept System inputs from RAS components or other sources, make decisions based on those inputs, or initiate output signals to take remedial actions.

b. Arming more load or generation than necessary such that failure of the RAS to drop a portion of load or generation due to that single component failure will still result in satisfactory System performance, as long as tripping the total armed amount of load or generation does not cause other adverse impacts to reliability.

c. Using alternative automatic actions to back up failures of single RAS components.

d. 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.

5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies important RAS information for each existing RAS to be retired that the RAS-entity shall document and provide to the Reliability Coordinator for review pursuant to Requirement R1.

1. Information necessary to ensure that the Reliability Coordinator is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of technical studies and technical justifications, if applicable, upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

While the documentation necessary to evaluate RAS removals is not as extensive as for new or functionally modified RAS, it is still vital that, when the RAS is no longer available, System performance will still meet the appropriate (usually TPL) requirements for the Contingencies or System conditions that the RAS had been installed to remediate.

Technical Justification for Attachment 2 Content

Reliability Coordinator RAS Review Checklist

Attachment 2 is a checklist provided to facilitate consistent reviews continent-wide for new or functionally modified RAS prior to the RAS installation. The checklist is meant to assist the RC in identifying reliability-related considerations relevant to various aspects of RAS design and implementation.

Technical Justifications for Attachment 3 Content

Database Information

Attachment 3 contains the minimum information that the RC must consolidate into its database for each RAS in its area.

1. RAS name.
    - The name used to identify the RAS.
2. Each RAS-entity and contact information.
    - A reliable phone number or email address should be included to contact each RAS-entity if more information is needed.
3. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent five full calendar year (Requirement R4) evaluation date; and, date of retirement, if applicable.
    - Specify each applicable date.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery).
    - A short description of the reason for installing the RAS is sufficient, as long as the main System issues addressed by the RAS can be identified by someone with a reliability need.
5. Description of the Contingencies or System conditions for which the RAS was designed (initiating conditions).
    - A high level summary of the conditions/Contingencies is expected. Not all combinations of conditions are required to be listed.
6. Corrective action taken by the RAS.
    - A short description of the actions should be given. For schemes shedding load or generation, the maximum amount of megawatts should be included.

7. Identification of limited impact[10] RAS.
    - Specify whether or not the RAS is designated as limited impact.
8. Any additional explanation relevant to high-level understanding of the RAS.
    - If deemed necessary, any additional information can be included in this section, but is not mandatory.

[10] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

Implementation Plan for PRC-012-2

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

Requested Approval

- PRC-012-2 – Remedial Action Schemes

Requested Withdrawals

- PRC-012-1 – Remedial Action Scheme Review Procedure
- PRC-013-1 – Remedial Action Scheme Database
- PRC-014-1 – Remedial Action Scheme Assessment

Requested Retirements

- PRC-015-1 – Remedial Action Scheme Data and Documentation
- PRC-016-1 – Remedial Action Scheme Misoperations

Applicable Entities

- Reliability Coordinator
- Planning Coordinator
- RAS-entity – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS

Background

On November 13, 2014, the NERC Board of Trustees approved revisions to the definition for Remedial Action Scheme ("RAS") and associated revisions to related Reliability Standards to consolidate that term with the Glossary term "Special Protection System" (SPS).

In its February 3, 2015 petition to the Commission for approval of the definition of RAS and associated Reliability Standards ("Petition"), NERC noted that, although PRC-012-0, PRC-013-0, and PRC-014-0 were neither approved nor remanded by the Commission in Order No. 693 and were therefore not enforceable, NERC revised these standards to account for the RAS definition revision and changed relevant version numbers to reflect the change. Because of this change, NERC requested retirement of PRC-012-0, PRC-013-0, and PRC-014-0, and provided, for informational purposes only, updated Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1. In the same Petition, NERC requested retirement of PRC-015-0 and PRC-016-0.1 and approval of Reliability Standards PRC-015-1 and PRC-016-1, again implementing changes stemming from the revised definition of RAS.

On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to accept the revisions to the RAS definition and associated standards, and on November 19, 2015, the Commission issued a Final Order approving the RAS definition and associated standards.

General Considerations

Reliability Standard PRC-012-2 was developed to consolidate previously unapproved standards which were designated by the Commission as "fill-in-the-blank" standards and to revise other RAS-related standards. Reliability Standard PRC-012-2 also provides clear and unambiguous responsibilities to the specific users, owners, and operators of the Bulk-Power System. Reliability Standard PRC-012-2 establishes a new working framework between RAS-entities, PCs, and RCs, and this new framework will involve considerable start-up effort. As such, implementation of Reliability Standard PRC-012-2 will occur over a thirty six (36) month period after approval of the standard by applicable governmental authorities.

Limited Impact RAS

A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type III in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 and is subject to all applicable requirements.

Effective Date

Where approval by an applicable governmental authority is required, Reliability Standard PRC-012-2 shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. Provisions concerning the initial performance of obligations under Requirements R4, R8, and R9 are outlined below.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction. Provisions concerning the initial performance of obligations under Requirements R4, R8, and R9 are outlined below.

Requirement R4

For existing RAS, initial performance of obligations under Requirement R4 must be completed within five (5) full calendar years after the effective date of PRC-012-2, as described above.

For new or functionally modified RAS, the initial performance of Requirement R4 must be completed within five (5) full calendar years after the date that the RAS is approved by the reviewing RC(s) under Requirement R3.

Requirement R8

For each RAS not designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within six (6) full calendar years after the effective date for PRC-012-2, as described above.

For each RAS designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within twelve (12) full calendar years after the effective date for PRC-012-2, as described above.

Requirement R9

For each Reliability Coordinator that does not have a RAS database, the initial obligation under Requirement R9 is to establish a database by the effective date of PRC-012-2.

Each Reliability Coordinator will perform the obligation of Requirement R9 within twelve full calendar months after the effective date of PRC-012-2, as described above.

Retirement of Existing Standards

The Reliability Standards for retirement shall be retired immediately prior to the effective date of PRC-012-2 in the particular jurisdiction in which the standard is becoming effective.

Implementation Plan for PRC-012-2

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

Requested Approval

- PRC-012-2 – Remedial Action Schemes

Requested Withdrawals

~~Requested Retirements~~

- PRC-012-1 – Remedial Action Scheme Review Procedure
- PRC-013-1 – Remedial Action Scheme Database
- PRC-014-1 – Remedial Action Scheme Assessment

Requested Retirements

- PRC-015-1 – Remedial Action Scheme Data and Documentation
- PRC-016-1 – Remedial Action Scheme Misoperations

Applicable Entities

- Reliability Coordinator
- Planning Coordinator
- RAS-entity – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS

Background

On November 13, 2014, the NERC Board of Trustees approved revisions to the definition for Remedial Action Scheme (“RAS”) and associated revisions to related Reliability Standards to consolidate that term with the Glossary term “Special Protection System” (SPS).

In its February 3, 2015 petition to the Commission for approval of the definition of RAS and associated Reliability Standards (“Petition”), NERC noted that, although PRC-012-0, PRC-013-0, and PRC-014-0 were neither approved nor remanded by the Commission in Order No. 693 and were therefore not enforceable, NERC revised these standards to account for the RAS definition revision and changed relevant version numbers to reflect the change. Because of this change, NERC requested retirement of PRC-012-0, PRC-013-0, and PRC-014-0, and provided, for informational purposes only, updated Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1. In the same Petition, NERC requested retirement of PRC-015-0 and PRC-

016-0.1 and approval of Reliability Standards PRC-015-1 and PRC-016-1, again implementing changes stemming from the revised definition of RAS.

On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to accept the revisions to the RAS definition and associated standards, and on November 19, 2015, the Commission issued a Final Order approving the RAS definition and associated standards.

General Considerations

Reliability Standard PRC-012-2 was developed to consolidate previously unapproved standards which were designated by the Commission as "fill-in-the-blank" standards and to revise other RAS-related standards. Reliability Standard PRC-012-2 also provides clear and unambiguous responsibilities to the specific users, owners, and operators of the Bulk-Power System. Reliability Standard PRC-012-2 establishes a new working framework between RAS-entities, PCs, and RCs, and this new framework will involve considerable start-up effort. As such, implementation of Reliability Standard PRC-012-2 will occur over a thirty six (36) month period after approval of the standard by applicable governmental authorities.

Limited Impact RAS

A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type ~~3~~ III in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 and is subject to all applicable requirements.

Effective Date

Where approval by an applicable governmental authority is required, Reliability Standard PRC-012-2 shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. Provisions concerning the initial performance of obligations under Requirements R4, R8, and R9 are outlined below.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction. Provisions concerning the initial performance of obligations under Requirements R4, R8, and R9 are outlined below.

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For existing RAS, initial performance of obligations under Requirement R4 must be completed within five (5) full calendar years after the effective date of PRC-012-2, as described above.

For new or functionally modified RAS, the initial performance of Requirement R4 must be completed within five (5) full calendar years after the date that the RAS is approved by the reviewing RC(s) under Requirement R3.

Requirement R8

For each RAS not designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within six (6) full calendar years after the effective date for PRC-012-2, as described above.

For each RAS designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within twelve (12) full calendar years after the effective date for PRC-012-2, as described above.

Requirement R9

For each Reliability Coordinator that does not have a RAS database, the initial obligation under Requirement R9 is to establish a database by the effective date of PRC-012-2.

Each Reliability Coordinator will perform the obligation of Requirement R9 within twelve full calendar months after the effective date of PRC-012-2, as described above.

Retirement of Existing Standards

The Reliability Standards for retirement shall be retired immediately prior to the effective date of PRC-012-2 in the particular jurisdiction in which the standard is becoming effective.

Revised Definition of “Special Protection System”

Special Protection System (SPS)

Background

In Order No. 693, the Commission approved, among other things, the *Glossary of Terms Used in NERC Reliability Standards* (“NERC Glossary”), which included NERC’s currently effective definitions of Special Protection System and Remedial Action Scheme. The NERC Glossary currently defines a Special Protection System as:

> An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

The currently effective NERC Glossary definition for “Remedial Action Scheme” is a cross-reference to the definition of Special Protection System and reads: “See ‘Special Protection System.’” This internal cross-reference from Remedial Action Scheme to Special Protection System in lieu of a separate definition was developed to ensure that the terms are used interchangeably even where entities or an interconnection uses one term versus the other.

On February 3, 2015, NERC submitted a petition for approval of a revised definition of “Remedial Action Scheme” to add clarity and to ensure proper identification of Remedial Action Schemes and a more consistent application of related Reliability Standards. As explained in the petition, “[t]he defined terms ‘Special Protection System’ and ‘Remedial Action Scheme’ are currently used interchangeably throughout the NERC Regions and in various Reliability Standards, including prior versions of the Proposed Reliability Standards.” Along with this proposed revised definition, NERC submitted revisions to various Reliability Standards by replacing the term “Special Protection System” and replacing it with the newly revised “Remedial Action Scheme.” As NERC stated, “use of only one term in the NERC Reliability Standards will ensure proper identification of these systems and application of related Reliability Standards.” The petition also anticipated future revision to the definition of “Special Protection System” to cross-reference the newly revised and proposed definition of “Remedial Action Scheme.” This coordination, which would be achieved by implementing the new definition of “Special Protection System” simultaneously with the Commission approval of the revised definition for “Remedial Action Scheme,” will ensure that all references to “Special Protection System” and “Remedial Action Scheme” refer to the same revised definition.

On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking (“NOPR”) proposing to accept the revisions to the RAS definition and associated standards, and on November 19, 2015, the Commission issued a Final Order approving the RAS definition and associated standards.

Revised Definition

Special Protection System (SPS)

See “Remedial Action Scheme”

~~Proposed~~ Revised Definition of "Special Protection System"

Special Protection System (SPS)

Background

In Order No. 693, the Commission approved, among other things, the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary"), which included NERC's currently effective definitions of Special Protection System and Remedial Action Scheme. The NERC Glossary currently defines a Special Protection System as:

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The currently~~-~~ effective NERC Glossary definition for "Remedial Action Scheme" is a cross-reference to the definition of Special Protection System and reads: "See 'Special Protection System.'" This internal cross-reference~~s~~ from Remedial Action Scheme to Special Protection System in lieu of a separate definition was developed to ensure that the terms are used interchangeably even where entities or an interconnection uses one term versus the other.

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On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking ("NOPR") proposing to accept the revisions to the RAS definition and associated standards, and on November 19, 2015, the Commission issued a Final Order approving the RAS definition and associated standards.

~~Proposed~~ Revised Definition

Special Protection System (SPS)

See “Remedial Action Scheme”

Implementation Plan for the Revised Definition of “Special Protection System”

Project 2010-05.3 – Remedial Action Scheme (RAS)

Requested Approval

- Definition of “Special Protection System”

Requested Retirement

- Existing definition of “Special Protection System”

Background

In Order No. 693, the Commission approved, among other things, the Glossary of Terms Used in NERC Reliability Standards (“NERC Glossary”), which included NERC’s currently effective definitions of Special Protection System and Remedial Action Scheme. The NERC Glossary currently defines a Special Protection System as:

> An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

The currently effective NERC Glossary definition for “Remedial Action Scheme” is a cross-reference to the definition of Special Protection System and reads: “See ‘Special Protection System.’” This internal cross-reference from Remedial Action Scheme to Special Protection System in lieu of a separate definition was developed to ensure that the terms are used interchangeably even where entities or an interconnection uses one term versus the other.

On February 3, 2015, NERC submitted a petition for approval of a revised definition of “Remedial Action Scheme” developed by the standard drafting team Project 2010-05.2 (SPS SDT). As explained in the petition, “[t]he defined terms ‘Special Protection System’ and ‘Remedial Action Scheme’ are currently used interchangeably throughout the NERC Regions and in various Reliability Standards, including prior versions of the Proposed Reliability Standards.” In developing a solution for this inconsistency, the SPS SDT revised the definition of Remedial Action Scheme to incorporate a higher level of specificity for schemes that are appropriately considered Remedial Action Schemes, to provide more consistent identification of Remedial Action Schemes across the NERC Regions, and to state the relationship between Protection Systems and Remedial Action Schemes. NERC also submitted revisions to various

Reliability Standards by replacing the term "Special Protection System" with the newly revised "Remedial Action Scheme." As NERC stated, the "use of only one term in the NERC Reliability Standards will ensure proper identification of these systems and application of related Reliability Standards."

On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking ("NOPR") proposing to accept the revisions to the RAS definition and associated standards, and on November 19, 2015, the Commission issued a Final Order approving the RAS definition and associated standards.

General Considerations

The petition for revisions to the Definition of "Remedial Action Scheme" and related Reliability Standards also anticipated revision of the definition of "Special Protection System" to cross-reference the newly revised definition of "Remedial Action Scheme." Coordination of the two terms was completed by the SPS SDT in this phase of the Project (Project 2010-05.3) and will implement the new definition of "Special Protection System" simultaneously with the effective date of the revised definition for "Remedial Action Scheme." By assigning simultaneous effective dates of the revised definition of "Special Protection System" and "Remedial Action Scheme," all references to either term in NERC or Regional Entity documents will refer to the same NERC Glossary definition.

Effective Dates

Where approval by an applicable governmental authority is required, the revised definition of Special Protection System shall become effective on the later of the effective date of the applicable governmental authority's order approving the revised definition of Special Protection System or the effective date of the revised definition of Remedial Action Scheme approved by the Commission on November 19, 2015.

Where approval by an applicable governmental authority is not required, the revised definition of Special Protection System shall become effective on the later of the day that it is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction, or the effective date of the revised definition of Remedial Action Scheme as approved by the Commission on November 19, 2015.

Retirement

The currently effective definition of Special Protection System shall be retired immediately prior to the effective date of the revised definition of Special Protection System in the particular jurisdiction in which the definition is becoming effective.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for the Revised Definition of “Special Protection System”

Project 2010-05.3 – Remedial Action Scheme (RAS)

Requested Approval

- Definition of “Special Protection System”

Requested Retirement

- Existing definition of “Special Protection System”

Background

In Order No. 693, the Commission approved, among other things, the Glossary of Terms Used in NERC Reliability Standards (“NERC Glossary”), which included NERC’s currently effective definitions of Special Protection System and Remedial Action Scheme. The NERC Glossary currently defines a Special Protection System as:

> An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

The currently~~-~~ effective NERC Glossary definition for “Remedial Action Scheme” is a cross-reference to the definition of Special Protection System and reads: “See ‘Special Protection System.’” This internal cross-reference~~s~~ from Remedial Action Scheme to Special Protection System in lieu of a separate definition was developed to ensure that the terms are used interchangeably even where entities or an interconnection uses one term versus the other.

On February 3, 2015, NERC submitted a petition for approval of a revised definition of “Remedial Action Scheme” developed by the standard drafting team Project 2010-05.2 (SPS SDT). As explained in the petition, “[t]he defined terms ‘Special Protection System’ and ‘Remedial Action Scheme’ are currently used interchangeably throughout the NERC Regions and in various Reliability Standards, including prior versions of the Proposed Reliability Standards.” In developing a solution for this inconsistency, the SPS SDT revised the definition of Remedial Action Scheme to incorporate a higher level of specificity for schemes that are appropriately considered Remedial Action Schemes, to provide more consistent identification of Remedial Action Schemes across the NERC Regions, and to state the relationship between Protection Systems and Remedial Action Schemes. NERC also submitted revisions to various

Reliability Standards by replacing the term "Special Protection System" with the newly revised "Remedial Action Scheme." As NERC stated, the "use of only one term in the NERC Reliability Standards will ensure proper identification of these systems and application of related Reliability Standards."

On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking ("NOPR") proposing to accept the revisions to the RAS definition and associated standards, and on November 19, 2015, the Commission issued a Final Order approving the RAS definition and associated standards.

General Considerations

The petition for revisions to the Definition of "Remedial Action Scheme" and related Reliability Standards also anticipated revision of the definition of "Special Protection System" to cross-reference the newly revised definition of "Remedial Action Scheme." Coordination of the two terms was completed by the SPS SDT in this phase of the Project (Project 2010-05.3) and will implement the new definition of "Special Protection System" simultaneously with the effective date of the revised definition for "Remedial Action Scheme." By assigning simultaneous effective dates of the revised definition of "Special Protection System" and "Remedial Action Scheme," all references to either term in NERC or Regional Entity documents will refer to the same NERC Glossary definition.

Effective Dates

Where approval by an applicable governmental authority is required, the revised definition of Special Protection System shall become effective on the later of the effective date of the applicable governmental authority's order approving the revised definition of Special Protection System or the effective date of the revised definition of Remedial Action Scheme approved by the Commission on November 19, 2015.

Where approval by an applicable governmental authority is not required, the revised definition of Special Protection System shall become effective on the later of the day that it is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction, or the effective date of the revised definition of Remedial Action Scheme as approved by the Commission on November 19, 2015.

Retirement

The currently effective definition of Special Protection System~~s~~ shall be retired immediately prior to the effective date of the revised definition of Special Protection System~~s~~ in the particular jurisdiction in which the definition is becoming effective.

Mapping Document

Project 2010-5.3 Phase 3 of Protection Systems: Remedial Action Schemes

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include: **R1.1.** Description of the process for submitting a proposed RAS for Regional Reliability Organization review. **R1.2.** Requirements to provide data that describes design, operation, and modeling of a RAS. **R1.3.** 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.	**<u>PRC-012-1 R.1.1</u>**: Covered by Requirements R1, R2 and R3 **<u>PRC-012-1 R.1.2</u>**: Covered by Requirement R1, Attachment 1 **<u>PRC-012-1 R.1.3</u>**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4, Part 4.1.5 **<u>PRC-012-1 R.1.4</u>**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2, and Requirement R4, Part 4.1.4	**R1.** Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. **R3.** Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator. **R4.** Each Planning Coordinator, at least once every five full calendar years, shall:

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1.4. Requirements to demonstrate 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. **R1.5.** Requirements to demonstrate the proposed RAS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures. **R1.6.** Regional Reliability Organization definition of misoperation. **R1.7.** Requirements for analysis and documentation of corrective action plans for all RAS misoperations. **R1.8.** Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure. **R1.9.** Determination, as appropriate, of maintenance and testing requirements.	**PRC-012-1 R.1.5**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4, Part 4.1.2 **PRC-012-1 R.1.6**: Covered by Requirement R5 **PRC-012-1 R.1.7**: Covered by Requirements R5 and R6 **PRC-012-1 R.1.8**: PRC-012-2 NERC Standards Development Process **PRC-012-1 R.1.9**: Covered by Requirement R8	**4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for limited impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.4.1** The BES shall remain stable. **4.1.4.2** Cascading shall not occur. **4.1.4.3** Applicable Facility Ratings shall not be exceeded. **4.1.4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		established by the Transmission Planner and the Planning Coordinator. **4.1.4.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator. **R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether:

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		5.1.1 The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s). **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R8.** Each RAS-entity shall participate in performing a functional test of each of its RAS to verify the overall RAS

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		performance and the proper operation of non-Protection System components: • At least once every six full calendar years for all RAS not designated as limited impact, or • At least once every twelve full calendar years for all RAS designated as limited impact
R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-013-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a RAS installed shall maintain a RAS database. The database shall include the following types of information:	**PRC-013-1 R1**: Covered by Requirement R9 **PRC-013-1 R1.1, R1.2, R1.3:** Covered by Requirement R9, Attachment 3	**R9.** Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once every twelve full calendar months.

Reliability Standard: PRC-013-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1.1. Design Objectives — Contingencies and system conditions for which the RAS was designed, **R1.2.** Operation — The actions taken by the RAS in response to Disturbance conditions, and **R1.3.** Modeling — Information on detection logic or relay settings that control operation of the RAS.		
R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years	**PRC-014-1 R1**: Covered by Requirement R4	**R4.** Each Planning Coordinator, at least once every five full calendar years, shall:

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
for compliance with NERC Reliability Standards and Regional criteria.		**4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for limited impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.4.1** The BES shall remain stable. **4.1.4.2** Cascading shall not occur. **4.1.4.3** Applicable Facility Ratings shall not be exceeded. **4.1.4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		established by the Transmission Planner and the Planning Coordinator. **4.1.4.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.
R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all RAS installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).	<u>**PRC-014-1 R2**</u>: Covered by Requirement R4	**R4.** Each Planning Coordinator, at least once every five full calendar years, shall: **4.1** Perform an evaluation of each RAS within its planning area to determine whether:

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.1.1 The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for limited impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.4.1** The BES shall remain stable. **4.1.4.2** Cascading shall not occur. **4.1.4.3** Applicable Facility Ratings shall not be exceeded. **4.1.4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.1.4.5 Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.
R3. The documentation of the Regional Reliability Organization's RAS assessment shall include the following elements: **R3.1.** Identification of group conducting the assessment and the date the assessment was performed. **R3.2.** Study years, system conditions, and contingencies analyzed in the technical studies on which the	<u>**PRC-014-1 R3**</u>: Covered by Requirement R4 <u>**PRC-014-1 R3.1 - R3.4**</u>: Covered by Requirement R4 <u>**PRC-014-1 R3.5**</u>: Covered by Requirement R6	**R4.** Each Planning Coordinator, at least once every five full calendar years, shall: **4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
assessment is based and when those technical studies were performed. **R3.3.** Identification of RAS that were found not to comply with NERC standards and Regional Reliability Organization criteria. **R3.4.** Discussion of any coordination problems found between a RAS and other protection and control systems. **R3.5.** Provide corrective action plans for non-compliant RAS.		**4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for limited impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.4.1** The BES shall remain stable. **4.1.4.2** Cascading shall not occur. **4.1.4.3** Applicable Facility Ratings shall not be exceeded. **4.1.4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. **4.1.4.5** Transient voltage responses shall be within acceptable limits as established by the

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		Transmission Planner and the Planning Coordinator. **4.1.5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator. **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8.

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall maintain a list of and provide data for existing and proposed RAS as specified in Reliability Standard PRC-013-1 R1.	**PRC-015-1 R1**: Covered by Requirement R1, Attachment 1	**R1.** Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located.
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-1_R1 prior to being placed in service.	**PRC-015-1 R2**: Covered by Requirements R1, Attachment 1; R2, Attachment 2; and R3	**R1.** Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. **R3.** Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide	Retired P81	N/A

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
documentation of RAS data and the results of Studies that show compliance of new or functionally modified RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).		

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall analyze its RAS operations and maintain a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-1_R1.	**PRC-016-1 R1**: Covered by Requirement R5	**R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall take corrective actions to avoid future misoperations.	**PRC-016-1 R2**: Covered by Requirements R6 and R7	**R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of:

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		• Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R7.** Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: **7.1** Implement the CAP. **7.2** Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).	<u>**PRC-016-1 R3**</u>: Covered by Requirements R5, R6, and R7, Attachment 1	**R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS.

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		5.1.2 The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s). **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R7.** Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: **7.1** Implement the CAP.

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		7.2 Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

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Mapping Document

Project 2010-5.3 Phase 3 of Protection Systems: Remedial Action Schemes

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include: **R1.1.** Description of the process for submitting a proposed RAS for Regional Reliability Organization review. **R1.2.** Requirements to provide data that describes design, operation, and modeling of a RAS. **R1.3.** 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.	**PRC-012-1 R.1.1**: Covered by Requirements R1, R2 and R3 **PRC-012-1 R.1.2**: Covered by Requirement R1, Attachment 1 **PRC-012-1 R.1.3**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4, Part 4.1.5 **PRC-012-1 R.1.4**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2, and Requirement R4, Part 4.1.4	**R1.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. **R3.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator. **R4.** Each Planning Coordinator, at least once every five full calendar years, shall:

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1.4. Requirements to demonstrate 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. **R1.5.** Requirements to demonstrate the proposed RAS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures. **R1.6.** Regional Reliability Organization definition of misoperation. **R1.7.** Requirements for analysis and documentation of corrective action plans for all RAS misoperations. **R1.8.** Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure. **R1.9.** Determination, as appropriate, of maintenance and testing requirements.	**PRC-012-1 R.1.5**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4, Part 4.1.2 **PRC-012-1 R.1.6**: Covered by Requirement R5 **PRC-012-1 R.1.7**: Covered by Requirements R5 and R6 **PRC-012-1 R.1.8**: PRC-012-2 NERC Standards Development Process **PRC-012-1 R.1.9**: Covered by Requirement R8	**4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for ~~“~~limited impact~~”~~ RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.4.1** The BES shall remain stable. **4.1.4.2** Cascading shall not occur. **4.1.4.3** Applicable Facility Ratings shall not be exceeded. **4.1.4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		established by the Transmission Planner and the Planning Coordinator. **4.1.4.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator. **R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether:

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		5.1.1 The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s). **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R8.** Each RAS-entity shall participate in performing a functional test of each of its RAS to verify the overall RAS

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		performance and the proper operation of non-Protection System components: • At least once every six full calendar years for all RAS not designated as limited impact, or • At least once every twelve full calendar years for all RAS designated as limited impact
R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-013-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a RAS installed shall maintain a RAS database. The database shall include the following types of information:	**<u>PRC-013-1 R1</u>**: Covered by Requirement R9 **<u>PRC-013-1 R1.1, R1.2, R1.3:</u>** Covered by Requirement R9, Attachment 3	**R9.** Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once every twelve full calendar months.

Reliability Standard: PRC-013-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1.1. Design Objectives — Contingencies and system conditions for which the RAS was designed, **R1.2.** Operation — The actions taken by the RAS in response to Disturbance conditions, and **R1.3.** Modeling — Information on detection logic or relay settings that control operation of the RAS.		
R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years	**PRC-014-1 R1**: Covered by Requirement R4	**R4.** Each Planning Coordinator, at least once every five full calendar years, shall:

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
for compliance with NERC Reliability Standards and Regional criteria.		**4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for ~~"~~limited impact~~"~~ RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.4.1** The BES shall remain stable. **4.1.4.2** Cascading shall not occur. **4.1.4.3** Applicable Facility Ratings shall not be exceeded. **4.1.4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		established by the Transmission Planner and the Planning Coordinator. **4.1.4.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.
R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all RAS installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).	**PRC-014-1 R2**: Covered by Requirement R4	**R4.** Each Planning Coordinator, at least once every five full calendar years, shall: **4.1** Perform an evaluation of each RAS within its planning area to determine whether:

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.1.1 The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for ~~"~~limited impact~~"~~ RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.4.1** The BES shall remain stable. **4.1.4.2** Cascading shall not occur. **4.1.4.3** Applicable Facility Ratings shall not be exceeded. **4.1.4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.1.4.5 Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.
R3. The documentation of the Regional Reliability Organization's RAS assessment shall include the following elements: **R3.1.** Identification of group conducting the assessment and the date the assessment was performed. **R3.2.** Study years, system conditions, and contingencies analyzed in the technical studies on which the	**PRC-014-1 R3**: Covered by Requirement R4 **PRC-014-1 R3.1 - R3.4**: Covered by Requirement R4 **PRC-014-1 R3.5**: Covered by Requirement R6	**R4.** Each Planning Coordinator, at least once every five full calendar years, shall: **4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
assessment is based and when those technical studies were performed. **R3.3.** Identification of RAS that were found not to comply with NERC standards and Regional Reliability Organization criteria. **R3.4.** Discussion of any coordination problems found between a RAS and other protection and control systems. **R3.5.** Provide corrective action plans for non-compliant RAS.		**4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for ~~“~~limited impact~~”~~ RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.4.1** The BES shall remain stable. **4.1.4.2** Cascading shall not occur. **4.1.4.3** Applicable Facility Ratings shall not be exceeded. **4.1.4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. **4.1.4.5** Transient voltage responses shall be within acceptable limits as established by the

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		Transmission Planner and the Planning Coordinator. **4.1.5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator. **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8.

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall maintain a list of and provide data for existing and proposed RAS as specified in Reliability Standard PRC-013-1 R1.	**PRC-015-1 R1**: Covered by Requirement R1, Attachment 1	**R1.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located.
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-1_R1 prior to being placed in service.	**PRC-015-1 R2**: Covered by Requirements R1, Attachment 1; R2, Attachment 2; and R3	**R1.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. **R3.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide	Retired P81	N/A

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
documentation of RAS data and the results of Studies that show compliance of new or functionally modified RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).		

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall analyze its RAS operations and maintain a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-1_R1.	**PRC-016-1 R1**: Covered by Requirement R5	**R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall take corrective actions to avoid future misoperations.	**PRC-016-1 R2**: Covered by Requirements R6 and R7	**R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of:

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		• Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R7.** Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: **7.1** Implement the CAP. **7.2** Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).	PRC-016-1 R3: Covered by Requirements R5, R6, and R7, Attachment 1	**R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS.

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		5.1.2 The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s). **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R7.** Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: **7.1** Implement the CAP.

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		7.2 Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

Mapping Document

Project 2010-5.3 Phase 3 of Protection Systems: Remedial Action Schemes

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include: **R1.1.** Description of the process for submitting a proposed RAS for Regional Reliability Organization review. **R1.2.** Requirements to provide data that describes design, operation, and modeling of a RAS. **R1.3.** 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.	<u>**PRC-012-1 R.1.1**</u>: Covered by Requirements R1, R2 and R3 <u>**PRC-012-1 R.1.2**</u>: Covered by Requirement R1, Attachment 1 <u>**PRC-012-1 R.1.3**</u>: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4, Part 4.1.5 <u>**PRC-012-1 R.1.4**</u>: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2, and Requirement R4, Part 4.1.4	**R1.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. **R3.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator. **R4.** Each Planning Coordinator, at least once every five full calendar years, shall:

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1.4. Requirements to demonstrate 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. **R1.5.** Requirements to demonstrate the proposed RAS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures. **R1.6.** Regional Reliability Organization definition of misoperation. **R1.7.** Requirements for analysis and documentation of corrective action plans for all RAS misoperations. **R1.8.** Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure. **R1.9.** Determination, as appropriate, of maintenance and testing requirements.	**PRC-012-1 R.1.5**: Covered by Requirement R1, Attachments 1, Requirement R2, Attachment 2 and Requirement R4, Part 4.1.2 **PRC-012-1 R.1.6**: Covered by Requirement R5 **PRC-012-1 R.1.7**: Covered by Requirements R5 and R6 **PRC-012-1 R.1.8**: PRC-012-2 NERC Standards Development Process **PRC-012-1 R.1.9**: Covered by Requirement R8	**4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for ~~"~~limited impact~~"~~ RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.4.1** The BES shall remain stable. **4.1.4.2** Cascading shall not occur. **4.1.4.3** Applicable Facility Ratings shall not be exceeded. **4.1.4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		established by the Transmission Planner and the Planning Coordinator. **4.1.4.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator. **R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether:

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		5.1.1 The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s). **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R8.** Each RAS-entity shall participate in performing a functional test of each of its RAS to verify the overall RAS

Reliability Standard: PRC-012-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		performance and the proper operation of non-Protection System components: • At least once every six full calendar years for all RAS not designated as limited impact, or • At least once every twelve full calendar years for all RAS designated as limited impact
R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-013-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a RAS installed shall maintain a RAS database. The database shall include the following types of information:	**PRC-013-1 R1**: Covered by Requirement R9 **PRC-013-1 R1.1, R1.2, R1.3:** Covered by Requirement R9, Attachment 3	**R9.** Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once every twelve full calendar months.

Reliability Standard: PRC-013-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1.1. Design Objectives — Contingencies and system conditions for which the RAS was designed, **R1.2.** Operation — The actions taken by the RAS in response to Disturbance conditions, and **R1.3.** Modeling — Information on detection logic or relay settings that control operation of the RAS.		
R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).	Retired P81	N/A

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years	**PRC-014-1 R1**: Covered by Requirement R4	**R4.** Each Planning Coordinator, at least once every five full calendar years, shall:

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
for compliance with NERC Reliability Standards and Regional criteria.		**4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for ~~"~~limited impact~~"~~ RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.4.1** The BES shall remain stable. **4.1.4.2** Cascading shall not occur. **4.1.4.3** Applicable Facility Ratings shall not be exceeded. **4.1.4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		established by the Transmission Planner and the Planning Coordinator. **4.1.4.5** Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.
R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all RAS installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).	<u>**PRC-014-1 R2**</u>: Covered by Requirement R4	**R4.** Each Planning Coordinator, at least once every five full calendar years, shall: **4.1** Perform an evaluation of each RAS within its planning area to determine whether:

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.1.1 The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed. **4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for ~~"~~limited impact~~"~~ RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.4.1** The BES shall remain stable. **4.1.4.2** Cascading shall not occur. **4.1.4.3** Applicable Facility Ratings shall not be exceeded. **4.1.4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		4.1.4.5 Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator. **4.1.5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.
R3. The documentation of the Regional Reliability Organization's RAS assessment shall include the following elements: **R3.1.** Identification of group conducting the assessment and the date the assessment was performed. **R3.2.** Study years, system conditions, and contingencies analyzed in the technical studies on which the	**<u>PRC-014-1 R3</u>**: Covered by Requirement R4 **<u>PRC-014-1 R3.1 - R3.4</u>:** Covered by Requirement R4 **<u>PRC-014-1 R3.5</u>**: Covered by Requirement R6	**R4.** Each Planning Coordinator, at least once every five full calendar years, shall: **4.1** Perform an evaluation of each RAS within its planning area to determine whether: **4.1.1** The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed.

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
assessment is based and when those technical studies were performed. **R3.3.** Identification of RAS that were found not to comply with NERC standards and Regional Reliability Organization criteria. **R3.4.** Discussion of any coordination problems found between a RAS and other protection and control systems. **R3.5.** Provide corrective action plans for non-compliant RAS.		**4.1.2** The RAS avoids adverse interactions with other RAS, and protection and control systems. **4.1.3** For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. **4.1.4** Except for ~~“~~limited impact~~”~~ RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following: **4.1.4.1** The BES shall remain stable. **4.1.4.2** Cascading shall not occur. **4.1.4.3** Applicable Facility Ratings shall not be exceeded. **4.1.4.4** BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator. **4.1.4.5** Transient voltage responses shall be within acceptable limits as established by the

Reliability Standard: PRC-014-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		Transmission Planner and the Planning Coordinator. **4.1.5** Except for limited impact RAS, 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 is designed. **4.2** Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator. **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8.

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall maintain a list of and provide data for existing and proposed RAS as specified in Reliability Standard PRC-013-1 R1.	**PRC-015-1 R1**: Covered by Requirement R1, Attachment 1	**R1.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located.
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-1_R1 prior to being placed in service.	**PRC-015-1 R2**: Covered by Requirements R1, Attachment 1; R2, Attachment 2; and R3	**R1.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. **R2.** Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. **R3.** Prior to placing a new or functionally modified RAS in-service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying issue(s) shall resolve each issue to obtain approval of the RAS from each reviewing Reliability Coordinator.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide	Retired P81	N/A

Reliability Standard: PRC-015-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
documentation of RAS data and the results of Studies that show compliance of new or functionally modified RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).		

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall analyze its RAS operations and maintain a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-1_R1.	**PRC-016-1 R1**: Covered by Requirement R5	**R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS. **5.1.2** The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).
R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall take corrective actions to avoid future misoperations.	**PRC-016-1 R2**: Covered by Requirements R6 and R7	**R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of:

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		• Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R7.** Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: **7.1** Implement the CAP. **7.2** Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.
R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).	**PRC-016-1 R3**: Covered by Requirements R5, R6, and R7, Attachment 1	**R5.** Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: **5.1** Participate in analyzing the RAS operational performance to determine whether: **5.1.1** The System events and/or conditions appropriately triggered the RAS.

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		5.1.2 The RAS responded as designed. **5.1.3** The RAS was effective in mitigating BES performance issues it was designed to address. **5.1.4** The RAS operation resulted in any unintended or adverse BES response. **5.2** Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s). **R6.** Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: • Being notified of a deficiency in its RAS pursuant to Requirement R4, or • Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or • Identifying a deficiency in its RAS pursuant to Requirement R8. **R7.** Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: **7.1** Implement the CAP.

Reliability Standard: PRC-016-1		
Existing Requirement in Reliability Standard	**Translation to New Standard or Other Action**	**New or revised Requirement in Proposed Reliability Standard PRC-012-2**
		7.2 Update the CAP if actions or timetables change. **7.3** Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

Violation Risk Factor and Violation Severity Level Justification Document

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

This document provides the standard drafting team (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-012-2. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC’s overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justifications for PRC-012-2, Requirement R1	
VRF for Requirement R1 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of an entity to submit Attachment 1 information to the responsible Reliability Coordinator for review prior to placing a new or modified RAS in service or retiring an existing RAS could introduce risks to the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R1 relates to two of these areas, specifically (i) protection systems and their coordination; and (ii) clearer criteria for operationally critical facilities. Requirement R1 mandates that entities comply with a review process for new or modified RAS or retirement of RAS. Among the elements of such reviews is the coordination between RAS and other RAS and between RAS and protection and control systems. Requirement R1 also mandates that the RAS-entity provide the Reliability Coordinator relevant RAS information regarding the design and implementation for each new or functionally modified RAS.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements, so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-012-1, Requirement 1, Parts R1.1 – R1.5 which specifies attributes of the RRO process to review RAS (R1.1), provision of pertinent RAS data (R1.2), dependability (R1.3) and security (R1.4) of design, and coordination with other RAS and protection systems (R1.5), and has a Medium VRF.
FERC VRF G4 Discussion	A medium VRF is appropriate for this requirement because failure of an entity to submit Attachment 1 information to the responsible Reliability Coordinator for review prior to placing a new or modified RAS in

VRF Justifications for PRC-012-2, Requirement R1	
VRF for Requirement R1 is Medium	
Guideline 4- Consistency with NERC Definitions of VRFs	service or retiring an existing RAS could introduce risks to the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The RAS-entity failed to provide the information identified in Attachment 1 to each Reliability Coordinator prior to placing a new or functionally modified RAS in service or retiring an existing RAS in accordance with Requirement R1.

VSL Justifications for PRC-012-2, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-012-1, Requirements R1.1 – R1.5 which had four established Levels of Non-Compliance. The requirement is binary with only a Severe VSL so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2b: N/A
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R2	
VRF for Requirement R2 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R2 because failure of a Reliability Coordinator to perform the RAS reviews and identify potential risks presented by the RAS could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R2 relates to one of these areas, specifically, protection systems and their coordination. Requirement R2 mandates that Reliability Coordinators review the RAS to determine if a RAS avoids adverse interactions with other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-014-1, Requirement R1, which is related to the review of RAS.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R2 because failure of a Reliability Coordinator to perform the RAS reviews and identify potential risks presented by the RAS could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R2	
VRF for Requirement R2 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90 full calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in accordance with Requirement R2.

VSL Justifications for PRC-012-2, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-014-0, Requirement R1 which also had four established Levels of Non-Compliance. This requirement has VSLs comparable to the established Levels of Non-Compliance in that requirement, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R3	
VRF for Requirement R3 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of a RAS entity to address the reliability issues identified during the RC review before placing it into service could introduce risks to the BES that could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R3 relates to one of these areas, specifically protection systems and their coordination. Requirement R3 requires the RAS-entity to address each identified reliability issue which includes the coordination between RAS and other RAS and between RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-015-0 Requirement R2 which requires the entity to comply with the RRO procedure as defined in PRC-012-1 Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of a RAS entity to address the reliability issues identified during the RC review before placing it into service could introduce risks to the BES that could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R3	
VRF for Requirement R3 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The RAS-entity failed to resolve identified reliability issue(s) to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in service or retiring an existing RAS in accordance with Requirement R3.

VSL Justifications for PRC-012-2, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-015-0, Requirement R2 which has four established VSLs. This requirement is binary with only a Severe VSL so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2b: N/A
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R4	
VRF for Requirement R4 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R4 because failure to perform the periodic evaluation could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R4 relates to one of these areas, specifically protection systems and their coordination. Requirement R4 mandates that entities perform periodic evaluations of each RAS to ensure that changes in System conditions have not changed the effectiveness of the RAS to mitigate the events or System conditions for which it was designed. Requirement R4 incorporates all actions necessary to determine if a RAS avoids adverse interactions with other RAS and protection and control systems
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-2, Requirement R3 which requires the assessment of the effectiveness of UVLS Programs.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R4 because failure to perform the periodic evaluation could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R4	
VRF for Requirement R4 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator performed the evaluation as specified in Requirement R4, but was late by less than or equal to 30 full calendar days.	The Planning Coordinator performed the evaluation as specified in Requirement R4, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Planning Coordinator performed the evaluation as specified in Requirement R4, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate one of the Parts 4.1.1 through 4.1.5.	The Planning Coordinator performed the evaluation as specified in Requirement R4, but was late by more than 90 full calendar days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate two or more of the Parts 4.1.1 through 4.1.5. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to provide the results to one or more of the

VSLs for PRC-012-2, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
			receiving entities listed in Part 4.2. OR The Planning Coordinator failed to perform the evaluation in accordance with Requirement R4.

VSL Justifications for PRC-012-2, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-014-0, Requirement R1 which has four established Levels of Non-Compliance. This requirement has comparable VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R4	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R4	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R5	
VRF for Requirement R5 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R5 because failure to perform the RAS operational performance analysis could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R5 relates to one of these areas, specifically protection systems and their coordination. Requirement R5 mandates that entities perform RAS operational performance analysis to verify that the RAS operation and the resulting System performance was consistent with the Contingency events or System conditions for which it was designed. Requirement R5 incorporates all actions necessary to identify coordination issues between RAS and other RAS and between RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-2, Requirements R4 which requires evaluation of the UVLS Program performance during a voltage excursion event.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R5 because failure to perform the RAS operational performance analysis could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R5	
VRF for Requirement R5 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity performed the analysis in accordance with Requirement R5, but was late by less than or equal to 10 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address one of the Parts 5.1.1 through 5.1.4.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address two or more of the Parts 5.1.1 through 5.1.4. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to provide the results (Part 5.2) to one or more of the reviewing Reliability Coordinator(s).

VSLs for PRC-012-2, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
			OR The RAS-entity failed to perform the analysis in accordance with Requirement R5

VSL Justifications for PRC-012-2, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0.1, Requirement R1, and PRC-012-1, Requirement R1.7, which have four established Levels of Non-Compliance. This requirement has comparable VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R5	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R5	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R6	
VRF for Requirement R6 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because the failure of an entity to develop a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R6 addresses one of these areas, specifically protection systems and their coordination. CAPs establish mitigation plans and timetable to address deficiencies that could cause adverse interactions between RAS and other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-016-0, Requirements R2 and R3 which require a RAS-owner take corrective actions to avoid future misoperations and provide documentation of the corrective action plans to the RRO.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because the failure of an entity to develop a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

VRF Justifications for PRC-012-2, Requirement R6	
VRF for Requirement R6 is Medium	
	preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30 full calendar days. OR The RAS-entity developed a Corrective Action Plan but failed to submit it to one or more of its reviewing Reliability Coordinator(s) in accordance with Requirement R6. OR

VSLs for PRC-012-2, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
			The RAS-entity failed to develop a Corrective Action Plan in accordance with Requirement R6.

VSL Justifications for PRC-012-2, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0, Requirements R2 and R3, and has VSLs comparable to the established Levels of Non-Compliance in those requirements, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R6	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R6	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R7	
VRF for Requirement R7 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of an entity to implement a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R7 relates to one of these areas, specifically protection systems and their coordination. Implemented CAPs address deficiencies that could cause adverse interactions between RAS and other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-016-0, Requirements R2 and R3 which require a RAS-owner take corrective actions to avoid future misoperations and provide documentation of the corrective action plans to the RRO.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of an entity to implement a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

VRF Justifications for PRC-012-2, Requirement R7	
VRF for Requirement R7 is Medium	
	preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity implemented a CAP in accordance with Requirement R7, Part 7.1, but failed to update the CAP (Part 7.2) if actions or timetables changed, or failed to notify (Part 7.3) each of the reviewing Reliability Coordinator(s) of the updated CAP or completion of the CAP.	N/A	N/A	The RAS-entity failed to implement a CAP in accordance with Requirement R7, Part 7.1.

VSL Justifications for PRC-012-2, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0, Requirement R2 and has VSLs comparable to the established Levels of Non-Compliance in that requirement, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Lower and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R8	
VRF for Requirement R8 is High	
NERC VRF Discussion	A High VRF is appropriate for this Requirement since failure to perform functional testing may allow latent failures to persist in a RAS. These latent failures could result in an unintended operation or a failure to operate, either of which could directly contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures. For these reasons, the requirement meets the NERC criteria for a High VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R8 has interactions in three of these areas, specifically (i) protection systems and their coordination, (ii) communication protocol and facilities, and (iii) appropriate use of transmission loading relief. RAS interactions occur with protection systems, utilize communication protocols and facilities for proper functioning, and are often used for transmission loading relief.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements, so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-005-3, Requirement R3 which requires the maintenance of Protection System Components and has a VRF of High.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A High VRF is appropriate for this Requirement since failure to perform functional testing may allow latent failures to persist in a RAS. These latent failures could result in an unintended operation or a failure to operate, either of which could directly contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures. For these reasons, the requirement meets the NERC criteria for a High VRF.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VRF Justifications for PRC-012-2, Requirement R8	
VRF for Requirement R8 is High	
mingle More than One Obligation	

VSLs for PRC-012-2, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by less than or equal to 30 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 90 full calendar days. OR The RAS-entity failed to perform the functional test for a RAS as specified in Requirement R8.

VSL Justifications for PRC-012-2, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-017-0, Requirements R1 and R2, which had VSLs of Lower, Moderate, High, and Severe. This requirement has VSLs comparable to the established VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R8	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R9	
VRF for Requirement R9 is Lower	
NERC VRF Discussion	A Lower VRF is appropriate for this requirement because the failure of an entity to update the RAS database, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R9 does not address any of the identified areas; therefore, the FERC VRF G1 Discussion is not applicable.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with PRC-010-2 Requirement R6 and PRC-006-1 Requirement R6, which have an approved VRF of Lower.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A Lower VRF is appropriate for this requirement because the failure of an entity to update the RAS database, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90 full calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

VSL Justifications for PRC-012-2, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-013-0, Requirement R1 and has VSLs comparable to the established Levels of Non-Compliance of that requirements, so there is no consequence of lowering the current level of compliance.

VSL Justifications for PRC-012-2, Requirement R9	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations**FERC VSL G3** Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is based upon a single violation, not a cumulative number of violations.The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

Violation Risk Factor and Violation Severity Level Justification Document

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

This document provides the standard drafting team (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-012-2. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justifications for PRC-012-2, Requirement R1	
VRF for Requirement R1 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of an entity to submit Attachment 1 information to the responsible Reliability Coordinator for review prior to placing a new or modified RAS in service or retiring an existing RAS could introduce risks to the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R1 relates to two of these areas, specifically (i) protection systems and their coordination; and (ii) clearer criteria for operationally critical facilities. Requirement R1 mandates that entities comply with a review process for new or modified RAS or retirement of RAS. Among the elements of such reviews is the coordination between RAS and other RAS and between RAS and protection and control systems. Requirement R1 also mandates that the RAS-entity provide the Reliability Coordinator relevant RAS information regarding the design and implementation for each new or functionally modified RAS.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements, so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-012-1, Requirement 1, Parts R1.1 – R1.5 which specifies attributes of the RRO process to review RAS (R1.1), provision of pertinent RAS data (R1.2), dependability (R1.3) and security (R1.4) of design, and coordination with other RAS and protection systems (R1.5), and has a Medium VRF.
FERC VRF G4 Discussion	A medium VRF is appropriate for this requirement because failure of an entity to submit Attachment 1 information to the responsible Reliability Coordinator for review prior to placing a new or modified RAS in

VRF Justifications for PRC-012-2, Requirement R1	
VRF for Requirement R1 is Medium	
Guideline 4- Consistency with NERC Definitions of VRFs	service or retiring an existing RAS could introduce risks to the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The RAS-entity failed to provide the information identified in Attachment 1 to each Reliability Coordinator prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R1.

VSL Justifications for PRC-012-2, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-012-1, Requirements R1.1 – R1.5 which had four established Levels of Non-Compliance. The requirement is binary with only a Severe VSL so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2b: N/A
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R2	
VRF for Requirement R2 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R2 because failure of a Reliability Coordinator to perform the RAS reviews and identify potential risks presented by the RAS could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R2 relates to one of these areas, specifically, protection systems and their coordination. Requirement R2 mandates that Reliability Coordinators review the RAS to determine if a RAS avoids adverse interactions with other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-014-1, Requirement R1, which is related to the review of RAS.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R2 because failure of a Reliability Coordinator to perform the RAS reviews and identify potential risks presented by the RAS could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R2	
VRF for Requirement R2 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90 full calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in accordance with Requirement R2.

VSL Justifications for PRC-012-2, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-014-0, Requirement R1 which also had four established Levels of Non-Compliance. This requirement has VSLs comparable to the established Levels of Non-Compliance in that requirement, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R2	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R3	
VRF for Requirement R3 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of a RAS entity to address the reliability issues identified during the RC review before placing it into service could introduce risks to the BES that could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R3 relates to one of these areas, specifically protection systems and their coordination. Requirement R3 requires the RAS-entity to address each identified reliability issue which includes the coordination between RAS and other RAS and between RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-015-0 Requirement R2 which requires the entity to comply with the RRO procedure as defined in PRC-012-1 Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of a RAS entity to address the reliability issues identified during the RC review before placing it into service could introduce risks to the BES that could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R3	
VRF for Requirement R3 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The RAS-entity failed to resolve identified reliability issue(s) to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in-service or retiring an existing RAS in accordance with Requirement R3.

VSL Justifications for PRC-012-2, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-015-0, Requirement R2 which has four established VSLs. This requirement is binary with only a Severe VSL so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The language included in the Severe VSL is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2b: N/A
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R3	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R4	
VRF for Requirement R4 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R4 because failure to perform the periodic evaluation could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R4 relates to one of these areas, specifically protection systems and their coordination. Requirement R4 mandates that entities perform periodic evaluations of each RAS to ensure that changes in System conditions have not changed the effectiveness of the RAS to mitigate the events or System conditions for which it was designed. Requirement R4 incorporates all actions necessary to determine if a RAS avoids adverse interactions with other RAS and protection and control systems
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-2, Requirement R3 which requires the assessment of the effectiveness of UVLS Programs.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R4 because failure to perform the periodic evaluation could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R4	
VRF for Requirement R4 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator performed the evaluation as specified in Requirement R4, but was late by less than or equal to 30 full calendar days.	The Planning Coordinator performed the evaluation as specified in Requirement R4, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Planning Coordinator performed the evaluation as specified in Requirement R4, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate one of the Parts 4.1.1 through 4.1.5.	The Planning Coordinator performed the evaluation as specified in Requirement R4, but was late by more than 90 full calendar days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate two or more of the Parts 4.1.1 through 4.1.5. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to provide the results to one or more of the

VSLs for PRC-012-2, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
			receiving entities listed in Part 4.2. OR The Planning Coordinator failed to perform the evaluation in accordance with Requirement R4.

VSL Justifications for PRC-012-2, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-014-0, Requirement R1 which has four established Levels of Non-Compliance. This requirement has comparable VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R4	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R4	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R5	
VRF for Requirement R5 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for Requirement R5 because failure to perform the RAS operational performance analysis could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R5 relates to one of these areas, specifically protection systems and their coordination. Requirement R5 mandates that entities perform RAS operational performance analysis to verify that the RAS operation and the resulting System performance was consistent with the Contingency events or System conditions for which it was designed. Requirement R5 incorporates all actions necessary to identify coordination issues between RAS and other RAS and between RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-010-2, Requirements R4 which requires evaluation of the UVLS Program performance during a voltage excursion event.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for Requirement R5 because failure to perform the RAS operational performance analysis could allow RAS with diminished effectiveness to go undetected which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.

VRF Justifications for PRC-012-2, Requirement R5	
VRF for Requirement R5 is Medium	
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity performed the analysis in accordance with Requirement R5, but was late by less than or equal to 10 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address one of the Parts 5.1.1 through 5.1.4.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address two or more of the Parts 5.1.1 through 5.1.4. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to provide the results (Part 5.2) to one or more of the reviewing Reliability Coordinator(s).

VSLs for PRC-012-2, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
			OR The RAS-entity failed to perform the analysis in accordance with Requirement R5

VSL Justifications for PRC-012-2, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0.1, Requirement R1, and PRC-012-1, Requirement R1.7, which have four established Levels of Non-Compliance. This requirement has comparable VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R5	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R5	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R6	
VRF for Requirement R6 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because the failure of an entity to develop a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R6 addresses one of these areas, specifically protection systems and their coordination. CAPs establish mitigation plans and timetable to address deficiencies that could cause adverse interactions between RAS and other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-016-0, Requirements R2 and R3 which require a RAS-owner take corrective actions to avoid future misoperations and provide documentation of the corrective action plans to the RRO.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because the failure of an entity to develop a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

VRF Justifications for PRC-012-2, Requirement R6	
VRF for Requirement R6 is Medium	
	preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30 full calendar days. OR The RAS-entity developed a Corrective Action Plan but failed to submit it to one or more of its reviewing Reliability Coordinator(s) in accordance with Requirement R6. OR

VSLs for PRC-012-2, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
			The RAS-entity failed to develop a Corrective Action Plan in accordance with Requirement R6.

VSL Justifications for PRC-012-2, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0, Requirements R2 and R3, and has VSLs comparable to the established Levels of Non-Compliance in those requirements, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R6	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	

VSL Justifications for PRC-012-2, Requirement R6	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R7	
VRF for Requirement R7 is Medium	
NERC VRF Discussion	A medium VRF is appropriate for this requirement because failure of an entity to implement a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R7 relates to one of these areas, specifically protection systems and their coordination. Implemented CAPs address deficiencies that could cause adverse interactions between RAS and other RAS and protection and control systems.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-016-0, Requirements R2 and R3 which require a RAS-owner take corrective actions to avoid future misoperations and provide documentation of the corrective action plans to the RRO.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A medium VRF is appropriate for this requirement because failure of an entity to implement a Corrective Action Plan allows identified risks due to a deficiency in a RAS to remain unmitigated which could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, a violation of this requirement, because it is in a planning time frame and Reliability Coordinators will mandate modified operating limits to maintain BES reliability, is unlikely, under emergency, abnormal, or restoration conditions anticipated by the

VRF Justifications for PRC-012-2, Requirement R7	
VRF for Requirement R7 is Medium	
	preparations, to lead to Bulk Electric System instability, separation, or cascading failures, or to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity implemented a CAP in accordance with Requirement R7, Part 7.1, but failed to update the CAP (Part 7.2) if actions or timetables changed, or failed to notify (Part 7.3) each of the reviewing Reliability Coordinator(s) of the updated CAP or completion of the CAP.	N/A	N/A	The RAS-entity failed to implement a CAP in accordance with Requirement R7, Part 7.1.

VSL Justifications for PRC-012-2, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-016-0, Requirement R2 and has VSLs comparable to the established Levels of Non-Compliance in that requirement, so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Lower and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

VSL Justifications for PRC-012-2, Requirement R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R8	
VRF for Requirement R8 is High	
NERC VRF Discussion	A High VRF is appropriate for this Requirement since failure to perform functional testing may allow latent failures to persist in a RAS. These latent failures could result in an unintended operation or a failure to operate, either of which could directly contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures. For these reasons, the requirement meets the NERC criteria for a High VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R8 has interactions in three of these areas, specifically (i) protection systems and their coordination, (ii) communication protocol and facilities, and (iii) appropriate use of transmission loading relief. RAS interactions occur with protection systems, utilize communication protocols and facilities for proper functioning, and are often used for transmission loading relief.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements, so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with NERC Reliability Standard PRC-005-3, Requirement R3 which requires the maintenance of Protection System Components and has a VRF of High.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A High VRF is appropriate for this Requirement since failure to perform functional testing may allow latent failures to persist in a RAS. These latent failures could result in an unintended operation or a failure to operate, either of which could directly contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures. For these reasons, the requirement meets the NERC criteria for a High VRF.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VRF Justifications for PRC-012-2, Requirement R8	
VRF for Requirement R8 is High	
mingle More than One Obligation	

VSLs for PRC-012-2, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by less than or equal to 30 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 90 full calendar days. OR The RAS-entity failed to perform the functional test for a RAS as specified in Requirement R8.

VSL Justifications for PRC-012-2, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-017-0, Requirements R1 and R2, which had VSLs of Lower, Moderate, High, and Severe. This requirement has VSLs comparable to the established VSLs so there is no consequence of lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-012-2, Requirement R8	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based upon a single violation, not a cumulative number of violations.

VRF Justifications for PRC-012-2, Requirement R9	
VRF for Requirement R9 is Lower	
NERC VRF Discussion	A Lower VRF is appropriate for this requirement because the failure of an entity to update the RAS database, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	In the VSL Order, FERC identified twelve critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System. Requirement R9 does not address any of the identified areas; therefore, the FERC VRF G1 Discussion is not applicable.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This requirement does not use sub-requirements so only one VRF was assigned. The VRF for this requirement is consistent with others in the standard with regard to relative risk; therefore, there is no conflict.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This requirement is consistent with PRC-010-2 Requirement R6 and PRC-006-1 Requirement R6, which have an approved VRF of Lower.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	A Lower VRF is appropriate for this requirement because the failure of an entity to update the RAS database, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement has only one reliability objective; therefore, this requirement does not co-mingle obligations.

VSLs for PRC-012-2, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90 full calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

VSL Justifications for PRC-012-2, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	While this requirement is new, it incorporates the reliability objectives of PRC-013-0, Requirement R1 and has VSLs comparable to the established Levels of Non-Compliance of that requirements, so there is no consequence of lowering the current level of compliance.

VSL Justifications for PRC-012-2, Requirement R9	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The language included in the Lower, Moderate, High, and Severe VSLs is clear and unambiguous, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations**FERC VSL G3** Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is based upon a single violation, not a cumulative number of violations.The VSL uses similar language to that used in the associated requirement and is therefore consistent with the requirement.

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

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

April 2016

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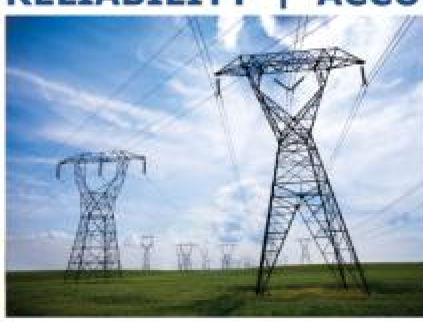


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Question & Answer for PRC-012-2

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 is the Remedial Action Scheme (RAS) review assigned to the Reliability Coordinator?

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 Reliability Coordinators (RCs) and Planning Coordinators (PCs) 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. The Wide Area purview 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, Planning Coordinator, Transmission Planner, or other entities 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 is not expected to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not contain compliance requirements. If Reliability Standards address functions that are not described in the model, the Reliability Standard requirements take precedence over the Functional Model. For further reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009. 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 five year evaluation of Requirement R4 assigned to the Planning Coordinator?

Requirement R4 states that an evaluation of each RAS must be done at least once every five full calendar years 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, similar to the planning analyses performed by PCs.

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

TOP-1-3 Requirement R13 requires Balancing Authorities (BA) and Transmission Operators (TOP) 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-005-4 requires RCs to share any pertinent data, such as data from RAS, with potentially affected BAs and TOPs. 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.

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

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 the RAS-entities. 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?

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 4.1.5 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.

Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as “limited impact” if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review processes and designated as Type III in NPCC or Local Area Protection Scheme (LAPS) in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process. Limited impact schemes are not subject to the single component failure aspect of Requirement R4, Part 4.1.5.

6. What is required for RAS “inadvertent operation” and why?

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-012-1 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 4.1.4 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 4.1.4.1 – 4.1.4.5, which are the performance requirements common to all planning events P0–P7.

Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as “limited impact” if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review processes and designated as Type III in NPCC or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator in conjunction with the RAS review process. Limited impact schemes are not subject to the single component malfunction aspect of Requirement R4, Part 4.1.4.

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 for continuity with PRC-012-1 R1.3; however, the standard drafting team concluded the classification is unnecessary. The distinction between planning and extreme RAS is captured in Requirement R4, Part 4.1.5 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.

Similarly, the standard drafting team concluded that the SPCS-SAMS distinction between significant and limited RAS was unnecessary for the purpose of maintaining continuity with PRC-012-1, and problematic due to the difficulty of drawing a universally satisfactory delineation in generally worded classification criteria. Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as “limited impact” if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review processes and designated as Type III in NPCC or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator in conjunction with the RAS review process.

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 a functional modification of a RAS?

A functional modification to a RAS consists of any of the following:

- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels (addition or removal)

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 device custom logic.
2. Changes to the telecommunication infrastructure or communication facility, such as the replacement of a T1 multiplexor that carries RAS communication when such changes may be important to the 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, or a component that uses the same functionality as the failed component.
2. A firmware upgrade of a RAS component if the change does not require changes in the RAS implementation logic.

The Supplemental Material section of Reliability Standard PRC-012-2 also includes several additional examples of RAS changes that do and do not constitute functional modifications.

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
NERC Staff	Al McMeekin (Standards Developer)	NERC
NERC Staff	Lacey Ourso (Standards Developer)	NERC
NERC Staff	Andrew Wills (Associate Counsel)	NERC

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

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

~~February~~ April 2016

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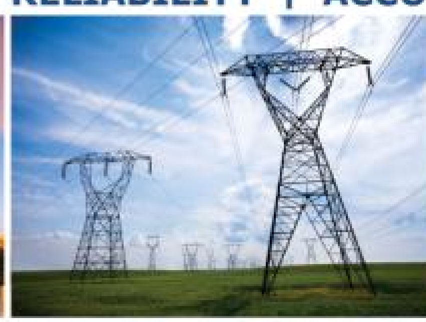


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- o Computers or programmable logic devices used to analyze information and provide RAS operational output

- 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.

Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review processes and designated as Type ~~3~~ III in NPCC or Local Area Protection Scheme (LAPS) in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process. Limited impact schemes are not subject to the single component failure aspect of Requirement R4, Part 4.1.5.

6. What is required for RAS "inadvertent operation" and why?

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-012-1 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 4.1.4 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 4.1.4.1 – 4.1.4.5, which are the performance requirements common to all planning events P0–P7.

Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective

date of this standard that has been through the regional review processes and designated as Type ~~3~~ III in NPCC or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator in conjunction with the RAS review process. Limited impact schemes are not subject to the single component malfunction aspect of Requirement R4, Part 4.1.4.

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 for continuity with PRC-012-1 R1.3; however, the standard drafting team concluded the classification is unnecessary. The distinction between planning and extreme RAS is captured in Requirement R4, Part 4.1.5 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.

Similarly, the standard drafting team concluded that the SPCS-SAMS distinction between significant and limited RAS was unnecessary for the purpose of maintaining continuity with PRC-012-1, and problematic due to the difficulty of drawing a universally satisfactory delineation in generally worded classification criteria. Within the RAS review process of PRC-012-2, there is a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review processes and designated as Type ~~3~~ III in NPCC or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator in conjunction with the RAS review process.

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 a functional modification of a RAS?

A functional modification to a RAS consists of any of the following:

- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels (addition or removal)

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 device custom logic.
2. Changes to the telecommunication infrastructure or communication facility, such as the replacement of a T1 multiplexor that carries RAS communication when such changes may be important to the 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, or a component that uses the same functionality as the failed component.
2. A firmware upgrade of a RAS component if the change does not require changes in the RAS implementation logic.

The Supplemental Material section of Reliability Standard PRC-012-2 also includes several additional examples of RAS changes that do and do not constitute functional modifications.

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
NERC Staff	Al McMeekin (Standards Developer)	NERC
NERC Staff	Lacey Ourso (Standards Developer)	NERC
NERC Staff	Andrew Wills (Associate Counsel)	NERC

Standards Announcement

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)
PRC-012-2 and Definition of "Special Protection System"

Final Ballots Open through April 29, 2016

Now Available

Final ballots for **PRC-012-2 – Remedial Action Schemes** and the **Revised Definition of "Special Protection System"** are open through **8 p.m. Eastern, Friday, April 29, 2016.**

Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pools may cast a vote. All ballot pool members may change their previously cast vote. A ballot pool member who failed to vote during the previous ballot period may vote in the final ballot period. If a ballot pool member does not participate in the final ballot, the member's vote from the previous ballot will be carried over as their vote in the final ballot.

Members of the ballot pools associated with this project may log in and submit their votes for the standard and definition here. If you experience any difficulties using the Standards Balloting & Commenting System (SBS), contact Wendy Muller.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

The voting results for the standard and definition will be posted and announced after the ballots close. If approved, the standard and definition will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)
PRC-012-2 and Definition of "Special Protection System"

Final Ballot Results

Now Available

Final ballots for **PRC-012-2 – Remedial Action Schemes** and the **Revised Definition of "Special Protection System"** concluded **8 p.m. Eastern, Friday, April 29, 2016.**

The voting statistics are listed below, and the Ballot Results page provides detailed results for the ballots.

	Quorum / Approval
PRC-012-2	81.19% / 80.36%
Definition of "Special Protection System"	87.15% / 93.43%

Next Steps

The standard and definition will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Al McMeekin (via email), or at (404) 446-9675.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

BALLOT RESULTS

Ballot Name: 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes PRC-012-2 FN 4 ST
Voting Start Date: 4/20/2016 11:54:00 AM
Voting End Date: 4/29/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 4
Total # Votes: 259
Total Ballot Pool: 319
Quorum: 81.19
Weighted Segment Value: 80.36

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	87	1	52	0.788	14	0.212	0	7	14
Segment: 2	9	0.8	7	0.7	1	0.1	0	0	1
Segment: 3	72	1	38	0.776	11	0.224	0	5	18
Segment: 4	23	1	12	0.75	4	0.25	0	1	6
Segment: 5	72	1	41	0.774	12	0.226	0	6	13
Segment: 6	44	1	25	0.758	8	0.242	0	4	7
Segment: 7	1	0.1	1	0.1	0	0	0	0	0
Segment: 8	2	0.1	1	0.1	0	0	0	0	1
Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment:	8	0.8	7	0.7	1	0.1	0	0	0

10									
Totals:	319	6.9	185	5.545	51	1.355	0	23	60

BALLOT POOL MEMBERS

Show All ▾ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		None	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Negative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Negative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith		Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican	Terry Harbour		Affirmative	N/A

	Energy Co.				
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Negative	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		None	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Cleco Corporation	John Lindsey		None	N/A
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		None	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Negative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Negative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A

1	Hydro One Networks, Inc.	Payam Farahbakhsh		Negative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		None	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Alan MacNaughton		None	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and	Mike ONeil		Affirmative	N/A

	Light Co.				
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Rod Kinard		Negative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Jared Shakespeare		Negative	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Abstain	N/A
1	Platte River Power Authority	John Collins		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Negative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District	Michiko Sell		None	N/A

	No. 2 of Grant County, Washington				
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Tim Kelley		Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Negative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		None	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Bertha Ellen Watkins		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	N/A
1	Transmission Agency of Northern California	Eric Olson		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A

1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Kim Moulton		None	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas		Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Michael DeLoach		None	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Negative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Valerie Reis		Negative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A

3	Beaches Energy Services	Steven Lancaster		None	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Negative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Green Cove Springs	Mark Schultz		None	N/A
3	City of Leesburg	Chris Adkins		None	N/A
3	City of Redding	Elizabeth Hadley		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A

3	Florida Power & Light	Summer Esquerre		None	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	N/A
3	Grand River Dam Authority	Jeff Wells		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker		Negative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Negative	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		None	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A

3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Blaine Dinwiddie		None	N/A
3	Pacific Gas and Electric Company	John Hagen		None	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Abstain	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Negative	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		Abstain	N/A
3	Puget Sound Energy, Inc.	Andrea Basinski		Affirmative	N/A
3	Sacramento Municipal Utility District	Rachel Moore		Affirmative	N/A
3	Salt River Project	John Coggins		None	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		None	N/A
3	Seattle City Light	Dana Wheelock		Negative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		None	N/A
3	Snohomish County	Mark Oens		Affirmative	N/A

	PUD No. 1				
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Negative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Negative	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		None	N/A
4	City of Clewiston	Lynne Mila		None	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		None	N/A
4	City of Redding	Nick Zettel		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Abstain	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A

4	Georgia System Operations Corporation	Guy Andrews		Negative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A
4	Keys Energy Services	Stanley Rzad		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		None	N/A
4	Sacramento Municipal Utility District	Michael Ramirez		Affirmative	N/A
4	Seattle City Light	Hao Li		Negative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	N/A
5	Austin Energy	Jeanie Doty		Negative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	Basin Electric Power	Mike Kraft		Affirmative	N/A

	Cooperative				
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	N/A
5	Bonneville Power Administration	Francis Halpin		Negative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	N/A
5	Calpine Corporation	Hamid Zakery		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City and County of San Francisco	Daniel Mason		Negative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City of Redding	Paul Cummings		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Dynegy Inc.	Dan Roethemeyer		Abstain	N/A
5	Edison International - Southern California	Thomas Rafferty		None	N/A

	Edison Company				
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		None	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		None	N/A
5	Florida Municipal Power Agency	David Schumann		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble		Negative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		None	N/A
5	Kissimmee Utility Authority	Mike Blough		Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Lower Colorado River Authority	Wesley Maurer		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A

5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		None	N/A
5	Oglethorpe Power Corporation	Teresa Czyz		Negative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Abstain	N/A
5	PPL Electric Utilities Corporation	Dan Wilson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Abstain	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz		Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A

5	SCANA - South Carolina Electric and Gas Co.	Henry Delk		None	N/A
5	Seattle City Light	Mike Haynes		Negative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Affirmative	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		None	N/A
5	WEC Energy Group, Inc.	Linda Horn		Negative	N/A
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Negative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Bonneville Power Administration	Alex Spain		Negative	N/A
6	City of Redding	Marvin Briggs		Affirmative	N/A

6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Edison International - Southern California Edison Company	Earle Saunders		Affirmative	N/A
6	Exelon	Maggy Powell		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges		Negative	N/A
6	Great River Energy	Donna Stephenson		None	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		None	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A

6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	Platte River Power Authority	Carol Ballantine		Abstain	N/A
6	Portland General Electric Co.	Adam Menendez		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Negative	N/A
6	Sacramento Municipal Utility District	Diane Clark		Affirmative	N/A
6	Salt River Project	William Abraham		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Negative	N/A
6	Xcel Energy, Inc.	Peter Colussy		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A

8	David Kiguel	David Kiguel		None	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 319 of 319 entries

BALLOT RESULTS

Ballot Name: 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes Definition FN 2 DEF
Voting Start Date: 4/20/2016 11:53:27 AM
Voting End Date: 4/29/2016 8:00:00 PM
Ballot Type: DEF
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 278
Total Ballot Pool: 319
Quorum: 87.15
Weighted Segment Value: 93.43

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	87	1	66	0.93	5	0.07	0	9	7
Segment: 2	9	0.8	8	0.8	0	0	0	0	1
Segment: 3	72	1	49	0.925	4	0.075	0	7	12
Segment: 4	23	1	17	0.895	2	0.105	0	3	1
Segment: 5	72	1	48	0.906	5	0.094	0	4	15
Segment: 6	44	1	33	0.892	4	0.108	0	3	4
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment:	8	0.8	8	0.8	0	0	0	0	0

10									
Totals:	319	6.9	232	6.446	20	0.454	0	26	41

BALLOT POOL MEMBERS

Show All ▾ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	paul johnson		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	American Transmission Company, LLC	Andrew Pusztai		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Negative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith		Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican	Terry Harbour		Affirmative	N/A

	Energy Co.				
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Bryan Texas Utilities	John Fontenot		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Cleco Corporation	John Lindsey		Affirmative	N/A
1	Colorado Springs Utilities	Shawna Speer		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	CPS Energy	Glenn Pressler		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Negative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Negative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	N/A

1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Alan MacNaughton		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and	Mike ONeil		Affirmative	N/A

	Light Co.				
1	NiSource - Northern Indiana Public Service Co.	Justin Wilderness		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Rod Kinard		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Jared Shakespeare		None	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Abstain	N/A
1	Platte River Power Authority	John Collins		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Negative	N/A
1	Public Utility District	Michiko Sell		Affirmative	N/A

	No. 2 of Grant County, Washington				
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Tim Kelley		Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Bertha Ellen Watkins		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Transmission Agency of Northern California	Eric Olson		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A

1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Kim Moulton		None	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Affirmative	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas		Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Michael DeLoach		None	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Valerie Reis		Negative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A

3	Beaches Energy Services	Steven Lancaster		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Green Cove Springs	Mark Schultz		Affirmative	N/A
3	City of Leesburg	Chris Adkins		Affirmative	N/A
3	City of Redding	Elizabeth Hadley		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		None	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A

3	Florida Power & Light	Summer Esquerre		None	N/A
3	Georgia System Operations Corporation	Scott McGough		Abstain	N/A
3	Grand River Dam Authority	Jeff Wells		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker		Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A

3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	Blaine Dinwiddie		None	N/A
3	Pacific Gas and Electric Company	John Hagen		None	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Abstain	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		Abstain	N/A
3	Puget Sound Energy, Inc.	Andrea Basinski		Affirmative	N/A
3	Sacramento Municipal Utility District	Rachel Moore		Affirmative	N/A
3	Salt River Project	John Coggins		None	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Dana Wheelock		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County	Mark Oens		Negative	N/A

	PUD No. 1				
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Negative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Negative	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		Affirmative	N/A
4	City of Clewiston	Lynne Mila		Affirmative	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	City of Redding	Nick Zettel		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Abstain	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A

4	Georgia System Operations Corporation	Guy Andrews		Abstain	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A
4	Keys Energy Services	Stanley Rzad		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Negative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		Affirmative	N/A
4	Sacramento Municipal Utility District	Michael Ramirez		Affirmative	N/A
4	Seattle City Light	Hao Li		Abstain	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Affirmative	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Negative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power	Mike Kraft		Affirmative	N/A

	Cooperative				
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Eric Schwarzrock		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Abstain	N/A
5	Bonneville Power Administration	Francis Halpin		Negative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	N/A
5	Calpine Corporation	Hamid Zakery		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City and County of San Francisco	Daniel Mason		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City of Redding	Paul Cummings		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		None	N/A
5	Dynegy Inc.	Dan Roethemeyer		Affirmative	N/A
5	Edison International - Southern California	Thomas Rafferty		Affirmative	N/A

	Edison Company				
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		None	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble		Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		None	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Lower Colorado River Authority	Wesley Maurer		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego		Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A

5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		None	N/A
5	Oglethorpe Power Corporation	Teresa Czyz		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Affirmative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	PPL Electric Utilities Corporation	Dan Wilson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Negative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz		Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A

5	SCANA - South Carolina Electric and Gas Co.	Henry Delk		None	N/A
5	Seattle City Light	Mike Haynes		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		None	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Affirmative	N/A
5	Utility System Efficiencies, Inc. (USE)	Catrina Martin		None	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	City of Redding	Marvin Briggs		Affirmative	N/A

6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Edison International - Southern California Edison Company	Earle Saunders		Affirmative	N/A
6	Exelon	Maggy Powell		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy		Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges		Affirmative	N/A
6	Great River Energy	Donna Stephenson		Negative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		None	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Negative	N/A

6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	Platte River Power Authority	Carol Ballantine		Affirmative	N/A
6	Portland General Electric Co.	Adam Menendez		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		Affirmative	N/A
6	Sacramento Municipal Utility District	Diane Clark		Affirmative	N/A
6	Salt River Project	William Abraham		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Negative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		None	N/A
6	Xcel Energy, Inc.	Peter Colussy		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A

8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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Exhibit I

Standard Drafting Team Roster

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Drafting Team Roster

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

	Participant	Entity
Chair	Gene Henneberg	NV Energy / Berkshire Hathaway Energy
Vice Chair	Bobby Jones	Southern Company
Members	Amos Ang	Southern California Edison
	Alan Engelmann	ComEd / Exelon
	Davis Erwin	Pacific Gas and Electric
	Sharma Kolluri	Entergy
	Charles-Eric Langlois	Hydro-Quebec TransEnergie
	Robert J. O'Keefe	American Electric Power
	Hari Singh	Xcel Energy
PMOS Liaison	Rod Kinard	Oncor Electric Delivery
NERC Staff	Al McMeekin – Senior Standards Developer	North American Electric Reliability Corporation
	Lacey Ourso – Standards Developer (Support)	North American Electric Reliability Corporation
	Andrew Wills – Associate Counsel	North American Electric Reliability Corporation