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