Consideration of Comments

Project Name: 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes | PRC-012-2

Comment Period Start Date: 8/20/2015

Comment Period End Date: 10/5/2015

Associated Ballot: 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes PRC-012-2 IN 1 ST

There were 60 responses, including comments from approximately 155 different people from approximately 104 different companies representing 9 of the 10 Industry Segments as shown on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Howard Gugel (via email) or at (404) 446-9693.

The drafting team made the following changes to the draft standard and implementation plan based on stakeholder comments:

Reliability Standard PRC-012-2

Applicability

Replaced the Transmission Planner with the Planning Coordinator.

Consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns a RAS.

Requirements

Requirement R1

Made minor clarifying changes.

Requirement R2

Made a minor clarifying change.

Requirement R3

Restructured for clarity.

Requirement R4

Restructured for clarity and included the RAS-entity as well as each impacted Transmission Planner and Planning Coordinator to Part 4.2 to receive the results of the RAS evaluation.

Included a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. Inserted a footnote for additional explanation.

Requirement R5

Restructured for clarity and added "on a mutually agreed upon schedule" to allow longer periods for the RAS operational analysis to be performed. Also changed from "analyze" to "participate in analyzing" for consistency with other requirements.

Requirement R6

Revised to include "Identifying a deficiency in its RAS pursuant to Requirement R8" as an additional trigger for the development of a CAP.

Requirement R7

Revised for clarity and added "and when the CAP is completed" to Part 7.3 regarding notification of the RC.

Requirement R8

Revised to provide a twelve full calendar year test interval for all RAS designated as limited impact. Also changed from “perform” to “participate in performing” for consistency with other requirements.

Requirement R9

Revised time period from “once each calendar year” to “once every twelve full calendar months”.

Measures, VSLs, and Attachments

Revised to be consistent with and complement the revised requirements.

Rationale Boxes and Supplemental Material

Revised to complement the revised requirements and provide additional examples and insight.

Implementation Plan

Requested Retirements

Removed references to Version 0 standards.

Applicable Entities

Replaced the Transmission Planner with the Planning Coordinator.

Consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns a RAS.

Background and General Considerations

Revised to reflect issuance of FERC Order No. 818 approving the RAS standards and definition of “Remedial Action Scheme.”

Effective Date

Changed the implementation period of the standard from twelve (12) months to thirty-six (36) months to provide entities more time to establish the new working frameworks among RAS-entities, Reliability Coordinators, and Planning Coordinators.

Added clarifying language for the initial performance of obligations under Requirements R4, R8, and R9.

Questions

Requirements R1, R2, and R3 pertain to the submittal of Attachment 1 information to the Reliability Coordinator (RC) for the review of a RAS, the RC using Attachment 2 as a guide for performing the RAS review, and the RC approving the RAS prior to the RAS being placed in service. Question 1 is relevant to these activities.

1. RAS review and approval: Do you agree with the RAS review process outlined by Requirements R1, R2, and R3? If no, please provide the basis for your disagreement and an alternate proposal.

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

2. RAS Periodic Evaluations: Do you agree with the RAS planning evaluation process outlined by Requirement R4? If no, please provide the basis for your disagreement and an alternate proposal.

3. RAS Inadvertent Operation: Do you agree with Requirement 4 Part 4.3 and Attachment 1 which stipulates that RAS inadvertent operation due to a single component malfunction still satisfies the System performance requirements common to TPL-001-4 P1-P7 events listed in Parts 4.3.1-4.3.5? (Note that this requirement remains the same as PRC-012-0 R1.4 except for the allowance for designed-in security that would prevent RAS inadvertent operation for any single component malfunction). If no, please provide the basis for your disagreement and an alternate proposal.

4. RAS Single Component Failure: Do you agree with Requirement 4 Part 4.4 and Attachment 1 which stipulates that any RAS intended to satisfy System performance requirements in a TPL standard must still satisfy those requirements when experiencing a single component failure? (Note that this requirement remains unchanged from PRC-012-0 R1.3.) If no, please provide the basis for your disagreement and an alternate proposal.

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

5. Corrective Action Plans: Do you agree that the application of Requirements R6 and R7 would address the reliability objectives associated with CAPs? If no, please provide the basis for your disagreement and an alternate proposal.

6. Implementation Plan: Do you agree with the Implementation Plan? If no, please provide the basis for your disagreement and an alternate proposal.

7. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Requirements R1, R2, and R3 pertain to the submittal of Attachment 1 information to the Reliability Coordinator (RC) for the review of a RAS, the RC using Attachment 2 as a guide for performing the RAS review, and the RC approving the RAS prior to the RAS being placed in service. Question 1 is relevant to these activities.

1. RAS review and approval: Do you agree with the RAS review process outlined by Requirements R1, R2, and R3? If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6

Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: No

Answer Comment:	The NSRF propose revising R2 to explicitly include the engagement of any applicable Planning Coordinators with wording like, "Each Reliability Coordinator . . . shall in conjunction with impacted Transmission Planners and Planning Coordinators . . ." The inclusion of Transmission Planners and Planning Coordinators is appropriate because RASs are 'standing, automatic' schemes that are evaluated primarily in the planning horizon and by Transmission Planners. In general, Reliability Coordinators do not have planning horizon analysis information or expertise. We further recommend that M2 and M3 be modified such that acceptable evidence can be a Reliability Coordinator sponsored peer review by impacted entities.

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

Acceptable evidence for Measure M2 is dated reports, checklists, or other documentation detailing the RAS review was performed, the aspect of "who" performed the review is not a factor. The drafting team declines to make the suggested change.

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:	Yes
Answer Comment:	Oncor Electric Delivery believes that it is a good idea to have an independent party review any RAS. However, 90 days for the review seems more reasonable since they are just reviewing the scheme. Additionally Oncor Electric Delivery believes the RAS information required in attachment 1 contains more than is necessary for a review and cannot always be obtained for every RAS. In fact, unless the RAS is an existing system during the review period there are usually no schematics to review so we do not believe it is appropriate to request schematic diagrams. The second bullet under General section I asks for "functionality of a new RAS", which would be

a relay functional diagram that depicts how the scheme works and that would be available during the review process.

Response: Thank you for your comments.

The time frame of four full calendar months is consistent with current utility and regional practices. The drafting team wrote the requirement to allow for time intervals longer or shorter than four full calendar months by including the phrase "mutually agreed upon schedule" among the affected parties. The drafting team declines to make the suggested change.

Attachment 1 lists information that is suppled to sufficiently define the electrical and physical location of a RAS. Schematic diagrams are listed as one example of information that may be useful but are not required. The reviewing RC will decide if any additional information is necessary beyond what the RAS-entity originally supplied on a case-by-case basis. The drafting team modeled the RAS information required in Attachment 1 after the current WECC and NPCC (WECC and NPCC combined represent approximately two-thirds of existing RAS in North America) design guides and review procedures documents which include details of the RAS design expectations and reviews. The drafting team maintains the level of detail specified in Attachment 1 is consistent with these common practices and declines to make the suggested change.

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3

Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Selected Answer: Yes

Chris Scanlon - Exelon - 1 -

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Selected Answer: Yes

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: Yes

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:	No
Answer Comment:	a. R1 references “each RAS-entity shall submit…”, but there should only be one RAS-entity per RAS, is this correct? b. The supplemental material of the Standard states that the RAS owners needs to select an RAS-entity or else the RC will select the RAS-entity. This language needs to be in the Standard if it’s going to be enforceable. c. For the designation of the RAS-entity between different owners, will NERC/FERC/Regions require a CFR or JRO agreement? And what happens if one of the RAS owners is not a NERC registered entity, i.e., not a functional entity? Please describe what evidence needs to be provided to show designation of responsibility to the RAS-entity. d. Also, most, if not all, new RASs are developed, studied, and reviewed within the long-term Planning Horizon by PCs and TPs. Modifications/retirements to existing RASs have the potential to be developed in the Operating Horizon; therefore, Seminole suggests that R1 be broken up into two requirements, one addressing modifications/retirements which would be specific to the “Operations Planning Horizon” and the second addressing “new” RASs specific to the “Long-term Planning Horizon” and applicable to PCs as well.

e. Can the drafting team define all of the components of an RAS so that "ownership" can be determined, i.e., what equipment makes up an RAS?

Response: Thank you for your comments.

a. Yes, you are correct.

b. The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS.

c. The drafting team notes that a JRO and a CFR, provided for in Sections 507 and 508 of the NERC Rules of Procedure, respectively, are voluntary registration relationships that entities may employ to accomplish registration responsibilities. Among other options for sharing registration responsibility, the JRO and CFR registration relationships can be implemented on ad hoc bases depending on the entities' unique circumstances. Per the definition, a RAS-owner (now RAS-entity) will be a Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. Each of these functional NERC registrations are defined in the NERC Rules of Procedure. As such, the drafting team does not foresee a situation when a RAS-entity would not be a NERC registered entity.

d. Existing regional RAS reviews do not make any distinction between RAS conceived or modified by planning or operating groups. The drafting team does not see any reliability benefit in bifurcating the RAS review process in this manner and declines to make the suggested change.

e. The drafting team revised Item 1 in the Implementation Section of Attachment 1 to better describe RAS components. The RC will make the final determination regarding the RAS components during its review.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

A. It is unclear why R3 is not structured consistent to R1 even though both requirements are prerequisites for achieving the same objective of "placing a new or functionally modified RAS in service or retiring an existing RAS". Suggest restructuring R3 as follows for clarity and consistency: "Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, the RAS-entity shall address each issue identified by the RAS review (performed pursuant to Requirement R2) and obtain approval of the RAS from each reviewing Reliability Coordinator."

B. In R1, the RAS review falls within the purview of one or more RC's depending on "the area(s) where the RAS is located." What attributes define the location of a RAS? Should the RAS location comprise of only the station(s) where its remedial action logic processing device(s) is/are installed? Or would the RAS location also include the stations from where the various RAS inputs are telemetered to the logic processing device? Would it also include the station(s) at which the RAS output(s) – that is, remedial actions – are sent? Suggest that the standard provides clear guidance on what comprises the RAS location. Alternatively, suggest using a different RAS characteristic in R1 to avoid subjective and inconsistent interpretations of what comprises RAS location.

Response: Thank you for your comments.

A. The drafting team made the suggested change.

B. The drafting team maintains that the RAS location may cover multiple Reliability Coordinator Area(s) that contain any aspect of a RAS (e.g., inputs, outputs, logic, or equipment) that allows the RAS to operate as-designed. The drafting team declines to make the suggested change.

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:	Yes

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer:	Yes

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:	No
Answer Comment:	Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Response: Please see the drafting team's responses to the referenced comments.

David Greene - SERC - 1,10 - SERC

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Selected Answer: Yes

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer: Yes

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment: ATC proposes revising R2 to explicitly include the engagement of any applicable Planning Coordinators with wording like, “Each Reliability Coordinator........ shall in conjunction with any Planning Coordinators ....” The inclusion of Planning Coordinators is appropriate because RASs are ‘standing, automatic’ schemes that are evaluated primarily in the planning horizon and by Transmission Planners. In general, Reliability Coordinators do not have planning horizon analysis information or expertise.

Response: Thank you for your comment.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the “flexibility” to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer:	No
Answer Comment:	The Planning Coordinator is the correct function to determine where a RAS Scheme is required. The need for an RAS is determined from TPL studies and planned system performance. References to the Reliability Coordinator should be changed to Planning Coordinator. The NERC Functional Model defines the RC as being "The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." It is not responsible for the planning or installation of a Protection System. The NERC Functional Model does not support the RC as being the reviewer. The RC currently does not review nor have the authority to approve any other facility or protection system installation.

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:	To remove possible confusion, “on a mutually agreed upon schedule” should be changed to “on a mutually agreed upon schedule between Reliability Coordinators and RAS-entities.”

Response: Thank you for your comment.

The drafting team maintains that the requirement is clear, the RC and the RAS-entity are the only parties mentioned in the requirement. The drafting team declines to make the suggested change.

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Selected Answer:	No
Answer Comment:	The Planning Coordinator is the correct function to determine where a RAS Scheme is required. The need for a RAS is determined from TPL studies and planned system performance. The standard correctly provides the RC with an opportunity to participate in providing opinion. The NERC Functional Model defines the RC as being “The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.” It is not responsible for the planning or installing a Protection System. The NERC Functional Model does not support the RC as being the reviewer. The RC currently does not review nor have the authority to approve any other facility or Protection System installation. Clarification of R3 regarding approval of the RAS after all issues have been addressed should

be made. The approval mentioned in R3 could be interpreted as an approval that each identified outstanding issue was addressed and not a complete formal approval of the RAS. If the RC is to perform the review, we suggest the following rewording for R3:

"Following the review performed pursuant to Requirement R2, the RAS-entity shall address each issue identified by the Reliability Coordinators participating in the review and obtain final approval(s) for the RAS from each Reliability Coordinator participating in the review, prior to placing a new or functionally modified RAS in service or retiring an existing RAS."

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional

Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Selected Answer: No

Answer Comment: The owner of any protection scheme should be responsible for the correct design and implementation of the scheme – RAS or not. Just like the design of switching to create a blackstart cranking path by a TOP in EOP-005-2, Requirement 6 must be verified by that TOP, the owner of the RAS should be held to the same expectation that the RAS is correctly designed and implemented. If the SDT still believes that some sort of review is required, then that review should be limited in scope to reviewing the generic content of the RAS design and not delve into the technical depth identified in some parts of Attachment 2.

Using the criteria outline by the SDT in its recent webinar, in addition to the independence of the reviewer and geographic span, the team also mentioned "expertise in planning, protection, operations, equipment". The attributes of this expertise to the level expected do not currently exist in most RC organizations. RC's are primarily operating entities (and even then primarily in real-time) and not experts in planning (beyond the operating time frame), protection or equipment. Transmission Owners, Transmission Operators and Transmission Planners normally have that expertise. The FERC acknowledged the limited RC technical expertise in evaluating details of restoration plans in its Order 749, Paragraph 38 ("…basis on which a reliability coordinator rejects a restoration plan will necessarily be based on generic engineering criteria…"). The review of a RAS by an RC should not be held to a higher expectation due to similar limited expertise with the equipment and systems involved in a RAS.

The "flexibility" for the RC granted in the requirement to designate a third party would seem to immediately invalidate the original assumptions that the RC has the compelling capability to adequately perform the review while meeting the SDT's characteristics of the reviewing entity. To allow this, while still requiring the RC to be responsible for the review, seems like an improper administrative burden and a potential compliance risk that the RC may assume because it had to find an entity more qualified than itself to perform the review. If an RC is not qualified to review all of the items in Attachment 2 then how can it be held responsible for the results of the review?

Regarding the designation of a third party reviewer, clarification needs to be made regarding what it means to “retain the responsibility for compliance.” Does this simply mean that the review takes place or that there is some implied resulting responsibility for the correct design and implementation that the RC is now accountable for.

Finally, also regarding the designation of a third party reviewer, is the term “third party” meant to be any entity not involved in the planning or implementation of the RAS?

The alterative to using the RC? Although there appears to be a movement to remove the RRO as a responsible entity from all standards, those organizations through their membership expertise and committee structures more closely match the characteristics stated by the SDT – expertise in planning/protection/operations/equipment, independence by virtue of the diversity of its members, wide area perspective, and continuity. If for some reason the SDT, believes that the RRO still should not be involved then an alternative could be the Planning Coordinator function which should have similar expertise to the Transmission Planners that are to specify/design a RAS per the functional model yet would have some independence which the SDT is looking for.

Response: Thank you for your comments.

The drafting team agrees that the owner of the RAS is responsible for the comprehensive design and detailed implementation of its RAS; however, the drafting team believes that an additional layer of review of the RAS should be performed. Because the RAS-owner (now RAS-entity) is the party that will ultimately design and implement its protection scheme, the RAS-entity is not an appropriate party to perform an independent review of its own system. Rather, in its original draft, the drafting team asserted that the Reliability Coordinator (RC), an entity with a requisite level of expertise and geographically expansive visibility, should perform a review of the RAS. Further, the drafting team maintains that, because results from previous reviews have shown that utilizing these metrics is both effective and efficient, the comprehensive RAS review to be performed by the RC that is currently performed by the regional entities should include the level of detail described in Attachments 1 and 2.

The drafting team is charged with assigning the requirements of the new standard to the specific users, owners, and operators of the Bulk-Power System while incorporating the reliability objectives of all the RAS/SPS-related standards. In drafting this standard, the team has worked diligently to minimize the changes that will be required from the existing processes. The drafting team maintains that the RC may, at its discretion, request information or assistance from other entities to perform the RAS review. This “flexibility” to request assistance from a third party allows the RC to perform a more robust review of the RAS if that party has a particular piece of information or can provide unique assistance. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform that review. To the contrary, this ability ensures a more effective RAS review. The drafting team explains in the Rationale for Requirement R2 that the RC “will retain the responsibility for compliance with this requirement” according to the standard’s explicit applicability to the RC.

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment: On the whole, Reclamation agrees with the RAS review process outlined in Requirements R1–R3. However, Reclamation believes that RAS-owners should also be listed in Attachment 1 and Attachment 3 and should be notified of all RAS-entity communications with the Reliability Coordinator (RC). Reclamation does not believe that the RAS-entity should be able to release technical information about a RAS-owner’s equipment without the knowledge of the RAS-owner.

Response: Thank you for your comments.

The drafting team maintains that each RAS-owner (now RAS-entity) would participate in producing the Attachment 1 data for a new or functionally modified RAS being submitted for review by the RAS-entity. The consolidation of the terms RAS-owner and RAS-entity effectively addresses your Attachment 3 comment.

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: No

Answer Comment: Florida Power & Light appreciates the efforts of the Standard drafting Team in consolidating the existing RAS-related Standards into one Standard (PRC-012), however we disagree with the assertion that the Reliability Coordinator (RC) is the best choice to review RAS's for new or continued implementation. The RC is responsible for the operation rather than the planning of the BES. RAS design and approval is best performed at the planning level. The Planning

Coordinator is responsible for coordinating transmission plans and protection systems and we believe more appropriate to review, approve and maintain the RAS database.

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Selected Answer: No

Answer Comment: The ISO/RTO Council Standards Review Committee (“SRC”) agrees that the RC should have to approve the use of RAS. Pursuant to the Functional Model, the RC does not have the authority to approve relay schemes. Nonetheless, it is important that the RC be informed of and understand how the RAS impacts the topology of its area of authority, identify and communicate any reliability issues to the RAS proponents, and coordinate with the RAS Entity regarding the in-service date and time of the RAS. We further recommend that M2 and M3 be modified such that acceptable evidence can be a Reliability Coordinator sponsored peer review with impacted Transmission Planners and Planning Coordinators.

Therefore, the SRC proposes that Requirement R3 be revised to:

R3. Following the review performed pursuant to Requirement R2, the RAS-entity shall address each identified issue and obtain concurrence from the Reliability Coordinator that all identified issues are resolved prior to placing a new or functionally modified RAS in service or retiring an existing RAS.

While the SRC is not opposed to a guideline regarding the performance of RAS evaluations, Attachment 2 is overly prescriptive and does not allow for impacted entities to utilize their operational experience and engineering judgment. The SRC recommends that the introductory paragraph to Attachment 2 be revised to provide greater flexibility regarding RAS evaluations. The following revisions are suggested:

The following checklist provides reliability related considerations for the Reliability Coordinator to consider for inclusion in its evaluation for each new or functionally modified2 RAS. The RC should utilize the checklist to determine those considerations that are applicable to the RAS evaluation being performed; however, RAS evaluations are not limited to the checklist items and the RC may request additional information on any reliability issue related to the RAS.

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

Acceptable evidence for Measure M2 is dated reports, checklists, or other documentation detailing the RAS review was performed, the aspect of "who" performed the review is not a factor. The drafting team declines to make the suggested change.

Please see the revision to Requirement R3 in the draft standard.

Please see the Supplemental Material section of the standard for the technical justification of Attachment 2. It reads: Attachment 2 is a checklist provided to assist the RC in identifying reliability considerations generally relevant to aspects of RAS design and implementation, and also for the purpose of facilitating consistent reviews continent-wide for each RAS to be installed or functionally modified. Most of the checklist items should be applicable to most RAS. There may be checklist items that are not applicable to a given RAS in which case they may be noted as not applicable and skipped in the RC review. Depending on the specifics of the RAS under review, it is possible that other reliability considerations may be identified during the review. Any other reliability considerations, along with their resolution with respect to the particular RAS under review, should be documented along with the Attachment 2 items that were applicable to the specific RAS under review.

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment: See comment in no. 7.

Response: Please see the drafting team's responses to the referenced comments.

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment: With regard to R1, the RAS entity is not typically qualified to provide some of the information required in Attachment 1, such as Sections II.3, II.4, II.5, and II.6. This information is typically developed by Planning Coordinator (PC) or

Transmission Planner (TP). RAS owners typically only implement the RAS as functionally required by the PC or TP. It is noted that the Planning Coordinator is not listed as an applicable entity and should be.

The Planning Coordinator is the correct function to determine where a RAS Scheme is required. The need for an RAS is determined from TPL studies and planned system performance. The standard correctly provides the RC with an opportunity to participate in providing opinion. The NERC Functional Model defines the RC as being "The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." It is not responsible for the planning or installation of a Protection System. The NERC Functional Model

does not support the RC as being the reviewer. The RC currently does not review nor have the authority to approve any other facility or protection system installation. Clarification of R3 regarding approval of the RAS after all issues have been addressed should be made. The approval mentioned in R3 could be interpreted as an approval that each identified outstanding issue was addressed not complete formal approval of the RAS. If the RC is to perform the review, we suggest the following:

R3- Following the review performed pursuant to Requirement R2, the RAS-entity shall address each issue identified by the Reliability Coordinators participating in the review and obtain final approval(s) for the RAS from each Reliability Coordinator participating in the review, prior to placing a new or functionally modified RAS in service or retiring an existing RAS.

With regard to R3, some of the identified issues would be most appropriately addressed by the PC or TP, especially the items in Section II of Attachment 1. It is inappropriate for RAS entity to assume compliance responsibility for addressing each identified issue.   The RAS owner for the RAS issues should be the responsible entity.

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the “flexibility” to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC’s Reliability Functional Model, Version 5, November 2009.

Acceptable evidence for Measure M2 is dated reports, checklists, or other documentation detailing the RAS review was <u>performed</u>, the aspect of “<u>who</u>” performed the review is not a factor. The drafting team declines to make the suggested change.

Please see the revision to Requirement R3 in the draft standard.

Please see the Supplemental Material section of the standard for the technical justification of Attachment 2. It reads: Attachment 2 is a checklist provided to assist the RC in identifying reliability considerations generally relevant to aspects of RAS design and implementation, and also for the purpose of facilitating consistent reviews continent-wide for each RAS to be installed or functionally modified. Most of the checklist items should be applicable to most RAS. There may be checklist items that are not applicable to a given RAS in which case they may be noted as not applicable and skipped in the RC review. Depending on the specifics of the RAS under review, it is possible that other reliability considerations may be identified during the review. Any other reliability considerations, along with their resolution with respect to the particular RAS under review, should be documented along with the Attachment 2 items that were applicable to the specific RAS under review.

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: No

Answer Comment:

As Dominion stated in its previous comments, we believe that RAS should be reviewed and approved in both the planning and operating horizons by designated entities within whose area(s) the Facility (ies) the RAS is designed to protect reside.

Dominion suggests the following specific changes to R1: Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity shall submit the information identified in Attachment 1 for review to the Reliability Coordinator(s) **and Transmission Planner(s) within whose respective** area(s) the **Element(s) or Facility(ies)** for which the RAS is **designed to protect is (are)** located..

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the “flexibility” to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Selected Answer: No

Answer Comment: See the comment in #7.1. In addition, the Transmission Planner should be a required participant in developing Attachment 1 and at least be responsible for Section II in Attachment 1. Finally, the obligation in R3 that a RAS-entity address issues identified pursuant to R2 is incomplete. R3 should also place compliance obligations on the Transmission Planner and the RAS-owners to participate in addressing any issues under R3.

Response: Thank you for your comments.

Please see the drafting team's responses to the referenced comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

Please see the revision to Requirement R3 in the draft standard.

Please see the Supplemental Material section of the standard for the technical justification of Attachment 2. It reads: Attachment 2 is a checklist provided to assist the RC in identifying reliability considerations generally relevant to aspects of RAS design and implementation, and also for the purpose of facilitating consistent reviews continent-wide for each RAS to be installed or functionally modified. Most of the checklist items should be applicable to most RAS. There may be checklist items that are not applicable to a given RAS in which case they may be noted as not applicable and skipped in the RC review. Depending on the specifics of the RAS under review, it is possible that other reliability considerations may be identified during the review. Any other reliability considerations, along with their resolution with respect to the particular RAS under review, should be documented along with the Attachment 2 items that were applicable to the specific RAS under review. Please see the revised Applicability section of the standard for the new description of a RAS-entity.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The RAS-entity is the best-suited entity to address any identified issues per Requirement R3. The drafting team maintains that the RAS-entity has the "flexibility" to request information or assistance from relevant entities (third parties).

Likes:	4	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla PSEG - PSEG Fossil LLC, 5, Kucey Tim PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
Dislikes:	0	

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10

David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Selected Answer: No

Answer Comment:

Regarding Requirement R1, the RAS-entity is not typically qualified to provide some of the information required in Attachment 1, such as Sections II.3, II.4, II.5, and II.6. This information is typically developed by the Planning Coordinator (PC) or Transmission Planner (TP). RAS-owners typically only implement the RAS as functionally required by the PC or TP. The Planning Coordinator should be listed as an applicable entity.

The Planning Coordinator is the correct function to determine where a RAS

Scheme is required. The need for a RAS is determined from TPL studies and planned system performance. The standard correctly provides the RC with an opportunity to participate in providing opinion. The NERC Functional Model defines the RC as being "The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." It is not responsible for the planning or installation of a Protection System. The NERC Functional Model does not support the RC as being the reviewer. The RC currently does not review nor have the authority to approve any other facility or protection system installation. Clarification of R3 regarding approval of the RAS after all issues have been addressed should be made. The approval mentioned in R3 could be interpreted as an approval that each identified outstanding issue was addressed not complete formal approval of the RAS. If the RC is to perform the review, we suggest the following:

R3- Following the review performed pursuant to Requirement R2, the RAS-entity shall address each issue identified by the Reliability Coordinators participating in the review and obtain final approval(s) for the RAS from each Reliability Coordinator participating in the review, prior to placing a new or functionally modified RAS in service or retiring an existing RAS.

Regarding Requirement R3 some of the identified issues would be most appropriately addressed by the PC or TP, especially the items in Section II of Attachment 1 as mentioned earlier. It is inappropriate for the RAS-entity to assume compliance responsibility for addressing each identified issue. The RAS-owner for the RAS issues should be the responsible entity.

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The RAS-entity is the best-suited entity to address any identified issues per Requirement R3. The drafting team maintains that the RAS-entity has the "flexibility" to request information or assistance from relevant entities (third parties).during the review. Any other reliability considerations, along with their resolution with respect to the particular RAS under review, should be documented along with the Attachment 2 items that were applicable to the specific RAS under review.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Answer Comment: ERCOT supports the comments submitted by the ISO/RTO Council.

Response: Thank you for your comments.

Please see the drafting team's responses to the referenced comments.

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: No

Answer Comment: PJM supports the comments submitted by the ISO/RTO Council.

Response: Thank you for your comments.

Please see the drafting team's responses to the referenced comments.

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer:	Yes

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer:	Yes

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:	No
Answer Comment:	R1, R2 and R3 do not differentiate between the functional aspects and design aspects of RAS. The functional requirements for a RAS, i.e. system conditions and triggering contingencies for which RAS is required as well as RAS actions to meet system performance requirement (as per TPL-001-4), are studied and identified by Transmission Planner and/or Planning Coordinator and not by the RAS owner/entity. The RAS owner/entity designs the RAS after TP or PC determines the functional requirements. The information listed in part II of attachment 1 is about functional requirements and can be provided by TP or PC. Most of the information listed in part I is repeat of part II. The rest, e.g., maps, one-line diagrams, in-service date, etc., can also be provided by TP or

PC who determined the functional requirements. The information in part III, which is related to the RAS design, is provided by the RAS owner/entity. RAS owners typically only implement the RAS as functionally required by the PC or TP. It is noted that the Planning Coordinator is not listed as an applicable entity and should be. With regard to R3, some of the identified issues would be most appropriately addressed by the PC or TP, especially the items in Section II of Attachment 1.

We suggest that R1, R2 and R3 and the related attachments be split in two parts: a) functional aspects, where TP or PC will be required to determine the functional requirements of the RAS and provide relevant information to RC for review, and b) design aspects, where RAS owner/entity will be required to design the RAS to meet those functional requirements and provide relevant information to RC for review.

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the “flexibility” to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The RAS-entity is the best-suited entity to address any identified issues per Requirement R3. The drafting team maintains that the RAS-entity has the "flexibility" to request information or assistance from relevant entities (third parties).during the review. Any other reliability considerations, along with their resolution with respect to the particular RAS under review, should be documented along with the Attachment 2 items that were applicable to the specific RAS under review.

Richard Vine - California ISO - 2 -

Selected Answer: No

Answer Comment:

The California ISO supports the comments of the ISO/RTO Standards Review Committee

Response: Thank you for your comments.

Please see the drafting team’s responses to the referenced comments.

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Dixie Wells - Lower Colorado River Authority - 5 -

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Selected Answer: Yes

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Selected Answer: Yes

Answer Comment: We agree with the checklist for the Reliability Coordinator to receive the proper information pertaining to the RAS and conducting a proper analysis. Additionally, we commend the drafting team for addressing the timing requirements in the Requirement R3 Rationale Box. We feel this will give the industry amply of enough time to address any issues identified by the Reliability Coordinator through their analysis.

Response: Thank you for your support.

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: No

Answer Comment: Florida Power and Light appreciates the efforts of the Standard Drafting Team in consolidating the exsiting RAS-related Standards into one Standard - PRC-012-2, however we disagree with the assertion that the Reliability Coordinator (RC) is the best choice to review the RAS's for new and continued implementation. The RC is responsible for the operation rather than the planning of the BES. RAS design and approval is best done at the Planning level. The Planning Coordinator is responsible for coordinating transmission plans and protection systems and we believe more appropriate to review, approve, and maintain the RAS database.

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the “flexibility” to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Yes

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment: In Requirement R3, the term “shall address” does not necessarily indicate the issue must be resolved as the Supplemental Material indicates. Texas RE recommends strengthening the requirement language to “shall resolve” or “shall implement”.

Response: Thank you for your comment.

The drafting team made the suggested change.

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Selected Answer: No

Answer Comment: 1. RAS review should be conducted by the Planning Coordinator and not the Reliability Coordinator. Oversight of the wide-area in the planning horizon is the job of the Planning Coordinator. This will be a significant amount of extra work for the RCs who should be focused on near-term operational reliability.

2. R1 should state a time frame the data should be submitted to the RC, such as four month prior to implementation of the RAS. Otherwise, the burden will be placed on the RC to conduct the study on the RAS-entities schedule.

3. There is no requirement to notify impacted neighboring entities. When a

RAS is implemented it can have a significant impact on neighboring entities. Neighboring entities need to have an opportunity to study the impact of the RAS.

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the “flexibility” to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC’s Reliability Functional Model, Version 5, November 2009.

The drafting team maintains that it is not necessary to specify how far in advance of implementation the RAS-entity must provide Attachment 1 data to the reviewing RC. Expeditious submittal of this information is in the interest of each RAS-entity to effect a timely implementation.

As noted above, the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. The drafting team contends that other Reliability Standards such TPL-001-4 provide avenues for neighboring entities to be notified well in advance of a new or modified RAS being implemented.

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:	No
Answer Comment:	R1, R2 and R3 do not differentiate between the functional aspects and design aspects of RAS. The functional requirements for a RAS, i.e. system conditions and triggering contingencies for which RAS is required as well as RAS actions to meet system performance requirements (as per TPL-001-4), are studied and identified by the TP and/or PC and not by the RAS owner/entity. The RAS owner/entity designs the RAS after the TP or PC determines its functional requirements. Therefore, the information listed in part II of attachment 1 is about functional requirements and can only be provided by a TP or PC in most instances. Most of the information listed in Part I is repeated in Part II. The remaining information listed, e.g., maps, one-line diagrams, in-service date, etc., can also be provided by the TP or PC, who determines the functional

requirements. The information in Part III, which is related to the RAS design, is provided by the RAS owner/entity.

Hydro One Networks Inc. suggests that R1, R2 and R3 and the related attachments be split in two parts: a) functional aspects, where the TP or PC will be required to determine the functional requirements of the RAS and provide relevant information to the RC for review, and b) design aspects, where the RAS owner/entity will be required to design the RAS to meet those functional requirements and provide relevant information to the RC for review.

In addition, it is inappropriate for the RAS entity to assume compliance responsibility for addressing each identified issue. The RAS owner for the RAS issues should be the responsible entity; this would be more in agreement with the assignment of accountabilities in R6.

Please also note our following comments with respect to relaxing the design review for a class of RAS.

Response: Thank you for your comments.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the “flexibility” to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The RAS-entity is the best-suited entity to address any identified issues per Requirement R3. The drafting team maintains that the RAS-entity has the "flexibility" to request information or assistance from relevant entities (third parties).during the review. Any other reliability considerations, along with their resolution with respect to the particular RAS under review, should be documented along with the Attachment 2 items that were applicable to the specific RAS under review.

Likes:	1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes:	0	

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer: No

Answer Comment:

R2 has an option of a four month schedule or a mutually agreed upon schedule. It is understood that setting a goal for a review within the operations time-frame is important, but it seems like the standard is trying to achieve two separate goals at once.

The first goal is to review the proposed change to determine whether it involves a CAP and identifies any current risks to reliability of the system which, as identified in the standard, might require use of System operating limits until the CAP is complete. This review needs to be completed quickly to minimize risk to the BES, but requires much less effort than a full review of the performance of the new RAS. In this instance four full-calendar months would seem to be too long of a time period.

The second goal is to complete the full review from a planning perspective. Each region already has a review and approval process in place. It seems arbitrary and unnecessary to impose the 4 month requirement rather than allowing the RC to follow a schedule or process it has already established. In this instance the four months would seem too short a time period in many cases due to the way these reviews are conducted (and by whom they are conducted) – so long as the risk to the BES reliability is already understood up-front, there is no reason to rush this portion of the work. In many cases, the RC in question may not possess the necessary staff / skills to perform what is required in Attachment 2, and may need to retain the services of others (consultants or perhaps area PCs or TPs), which will take time.

FMPA believes both issues could be resolved if R2 separated the near-term need to quickly assess BES reliability risk in the Operating Horizon from the long-term need to assess the details of the performance of the proposed scheme – particularly in cases where the proposed change is due to an identified issue with a subsequent CAP. Doing this first step on fast track would then allow each RC to define the schedule for the remaining review as per their regional practices.

Also, it would be beneficial to include all RAS-owners and their contact information in the RAS database.

Response: Thank you for your comments.

The time frame of four full calendar months is consistent with current utility and regional practices. The drafting team wrote the requirement to allow for time intervals longer or shorter than four full calendar months by including the phrase "mutually agreed upon schedule" among the affected parties. The RAS review associated with a CAP could and probably would require less than the four full calendar months. The drafting team disagrees that there is a reliability risk during the time interval associated with the CAP development though completion of the CAP because the Reliability Coordinator will require the RAS-entity to modify operating procedures, System configuration, generation dispatch, or employ other methods to alleviate the deficient RAS. The RAS review associated with new or functionally modified RAS is a more comprehensive review that entail the design, operations, and testing of the RAS. The drafting team declines to make the suggested change.

The drafting team modified the description of RAS-entity and eliminated RAS-owner. With this revised description, each RAS-entity (Transmission Owner, Generator Owner, or Distribution Provider) will be specifically identified in Attachments 1 and 3.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Selected Answer: No

Answer Comment: (1) We question why the RC was selected as the reviewing entity in this context. RC System Operators are not required to be “familiar with” (Reliability Standard PRC-001) or “have knowledge of” (proposed Reliability Standard TOP-009) the purpose and limitations of a RAS. Moreover, after the RC has conducted its initial review (Requirement R2) and the RAS-entity has addressed the identified issues, there is no timeframe required for the RC to conduct a final review for approval. We suggest rewording Requirement R3 to require both the RAS-entity and the RC to address each identified issue within a mutually agreed upon timeframe and concluded by a final RC review. Documentation regarding an approval of the RC following its final review should then be listed as acceptable evidence in Measure M3.

(2) We would also like the drafting team to state that an existing SPS will not need to go through the RC approval process even though the new definition of RAS could be applied as a new RAS device. The standard is unclear regarding which equipment will need to go through the RC approval process, existing SPS/RAS or new/changed RAS equipment? One possible solution is to state that all SPS and RAS equipment that are in service on the effective date of the proposed standard are considered RAS going forward and will not be required to go through the RC approval process.

Response: Thank you for your comment.

The drafting team maintains that the Reliability Coordinator (RC) is the best-suited functional entity to perform the RAS reviews because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The RC is also more likely to be independent of the entities involved in planning and implementing the RAS. The drafting team does not, by virtue of assigning the RAS review to the RC, expect the RC to possess more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not have compliance requirements. The drafting team is not precluded from developing Reliability Standards that address functions not described in the model. Reliability Standard requirements take precedence over the Functional Model. For reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009. As the drafting team stated in the Rationale and Supplemental Material section of the standard, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

The drafting team maintains that it is not necessary to specify how far in advance of implementation the RAS-entity must provide Attachment 1 data to the reviewing RC. Expeditious submittal of this information is in the interest of each RAS-entity to effect a timely implementation. In turn, the RC is well aware of the issues that the RAS is intended to solve, as well as the implications to the RAS-entity's schedule for delays. It is in the interest of the reviewing RC to expeditiously acknowledge when reliability issues are resolved so that the larger solution (the RAS) can be implemented. The drafting team declines to make the suggested change to the Requirement R3.

Requirement 1 is applicable to new or functionally modified RAS. Existing RAS will not need to go through the RC approval process unless they require functional modification. The drafting team declines to make the suggested change.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:	No
Answer Comment:	BPA believes R2's timeline of four-full-calendar months for RC review of RAS submission is too generous; it is inconsistent with regional practice. BPA proposes two weeks as appropriate, with less potential negative impact. The schedule should be short enough to accommodate the needs of the RAS owners and the "mutually agreed upon schedule" should apply if more time is needed.

Response: Thank you for your comment.

The time frame of four full calendar months is consistent with current utility and regional practices. The drafting team wrote the requirement to allow for time intervals longer or shorter than four full calendar months by including the phrase "mutually agreed upon schedule" among the affected parties. The drafting team declines to make the suggested change.

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

2. RAS Periodic Evaluations: Do you agree with the RAS planning evaluation process outlined by Requirement R4? If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer: Yes

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5

Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: No

Answer Comment: For R4, we propose revised wording to explicitly include any applicable Planning Coordinators with wording like, ". . . provide the results including any identified deficiencies to the RAS-owner(s), the reviewing Reliability Coordinators(s) and impacted Transmission Planners and Planning Coordinators."

Again, the inclusion of impacted Transmission Planners and Planning Coordinators is appropriate because these entities will generally have the best planning horizon information and expertise to review the evaluation.

Response: Thank you for your comments.

The drafting team revised the requirement to make the Planning Coordinator the responsible entity for performing the periodic evaluations.

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Selected Answer: Yes

Chris Scanlon - Exelon - 1 -

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Selected Answer: Yes

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment: We agree the Transmission Planner should periodically evaluate each RAS but there needs to be a mechanism by which the RAS-owners are required to share the RAS information with the Transmission Planner.

Response: Thank you for your comment.
The drafting team revised the requirement to make the Planning Coordinator (PC) the responsible entity for performing the periodic evaluations and requiring the PC to provide the results of the RAS evaluation to each reviewing Reliability Coordinator and each impacted Transmission Planner and RAS-entity.

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer:	Yes

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer:	Yes

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer:	No
Answer Comment:	The process is not clear about the responsibility for a RAS which is activated in multiple Transmission Planner areas such as WECC-1. The standard should clearly specify whose responsibility it is to perform

technical studies. APS suggests the following language:

"For a RAS which is activated in multiple Transmission Planning areas, a mutually agreed upon Transmission Planner of one of the multiple Transmission Planning areas shall perform an evaluation of the RAS at least once every 60-full-calendar-months and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies."

Response: Thank you for your comment.

The drafting team revised the requirement to make the Planning Coordinator (PC) the responsible entity for performing the periodic evaluations. The drafting team notes that the existing wording of the requirement allows the individual PCs to perform the evaluation of RAS within its own planning area, and also allows coordination of all relevant PCs to perform a joint evaluation of RAS that span multiple PC areas.

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer: No

Answer Comment:

a. For R4, can the TP merely provide the data to the RAS owners and the RAS-entity report the information to the RC?

b. In R4.2, please give additional detail as to what "adverse interactions" cover?

Response: Thank you for your comment.

The drafting team asserts that the results of the periodic evaluation should go directly to the Reliability Coordinator because if there is a deficiency identified in the RAS functionality, a change in System operations may be required. The drafting team maintains that adverse interactions covers inadvertently activating other RAS, mis-coordinating with Protection Systems or control systems.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:	No
Answer Comment:	The rationale and/or technical guidance does not make a convincing case for why the periodic evaluation of RAS must be a planning horizon analysis, and thus suited to be performed by Transmission Planner. As currently drafted, R4 seems to have an underlying premise that the periodic evaluation needs to be performed for the near-term planning horizon, which makes the periodic evaluation akin to the typical (future year) planning studies performed by Transmission Planner. However, the rationale for R4 does not provide any justification for the above. In fact, performing a planning horizon analysis is inconsistent with, if not contradictory to, the following reliability need stated in the rationale “A periodic evaluation is needed because (material) changes in system topology or operating conditions that have occurred since the previous RAS evaluation – or initial review – was completed…” Doesn’t this imply that the periodic RAS evaluation is for past changes, not the future

planned changes? If so, wouldn't the periodic RAS evaluation be more akin to Operational Planning Analysis (OPA) in the operating horizon? Is there a reason why an OPA would not be able to comprehensively address items 4.1 – 4.4 required for periodic RAS evaluation? We note that the existing R4 rationale makes an inadequate claim that "items required to be addressed in the evaluation are planning analyses", which is a weak basis for concluding that "consequently, the Transmission Planner is the functional entity best suited to perform the analyses." Based on all the above reasons, we contend that the reliability objectives of periodic RAS evaluation are more effectively achieved based on an operating horizon analysis like OPA. Therefore, the periodic RAS evaluation lends itself better to be performed by the Transmission Operator (or perhaps even the Reliability Coordinator).

Response: Thank you for your comment.

The evaluation in Requirement R4 is intended to verify the effectiveness and coordination of the RAS for the current System conditions as well as to verify that, if a RAS single component failure or single component malfunction were to occur, requirements for BES performance would continue to be satisfied. Operational Planning Analysis (OPA), by definition, look forward rather than backwards. The drafting team declines to make the suggested change.

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment: Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Response: Please see the drafting team’s responses to the referenced comments.

David Greene - SERC - 1,10 - SERC

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments

Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Selected Answer: Yes

Answer Comment: Suggest clarifying in R4 that the evaluation is a technical evaluation as stated below:
Each Transmission Planner shall perform a **technical evaluation (planning analyses)** of each RAS within its planning area at least once every 60-full-calendar-months and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies.

Response: Thank you for your comment.

The drafting team declines to make the suggested change.

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer: Yes

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment: For R4, ATC proposes revising the wording to explicitly include any applicable Planning Coordinators with wording like, ". . . provide the results including any identified deficiencies to the RAS-owner(s), the reviewing Reliability Coordinators(s) and any applicable Planning Coordinators."

Again, the inclusion of Planning Coordinators is appropriate because the Transmission Planner evaluation will be for the planning horizon and Planning Coordinators will generally have the best information and expertise to review the evaluation.

Response: Thank you for your comments.

The drafting team revised the requirement to make the Planning Coordinator the responsible entity for performing the periodic evaluations.

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: No

Answer Comment: The RAS-entity would be more appropriate to be specified in R4 instead of the RAS-owner

Response: Thank you for your comment.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS.

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Selected Answer: No

Answer Comment: The RAS-entity would be more appropriate to be specified in R4 instead of the RAS-owner.

Response: Thank you for your comment.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Selected Answer: Yes

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

David Kiguel - David Kiguel - 8 -

Selected Answer: No

Answer Comment: While generally supportive of this standard, I have concerns over assigning longer term assessment to Transmission Planner rather than to the Planning Coordinator.

Response: Thank you for your comment.

The drafting team revised the requirement and the Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4. The PC is the functional entity best suited to perform this evaluation because they have a wide-area planning perspective.

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer: No

Answer Comment:

1.

i. It is unclear why the Transmission Planner would provide results of the evaluation to each of the RAS-owner(s) and not the RAS-entity. A RAS typically operates as a single scheme and thus the RAS-entity can coordinate with all the RAS-owners regarding such evaluation results.

ii. ReliabilityFirst currently reviews each SPS at least once every five years for compliance with our Regional Criteria in accordance with fill-in-the-blank NERC standard PRC-012, Requirement R1. ReliabilityFirst has concerns with the 60 month review cycle in Requirement R4 as there may be instances in which a SPS which was reviewed by RF in the 2000 timeframe could theoretically not be reviewed until the 2020 timeframe. ReliabilityFirst believes a potential gap of 10 years in between reviews may have reliability impact. In order to prevent such a potential gap, ReliabilityFirst recommends the following recommendation for consideration:

a. Each Transmission Planner shall perform an evaluation of each RAS within its planning area at least once every 60-full-calendar-months **[since its last evaluation]** and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether:

Response: Thank you for your comment.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS.

The drafting team revised the requirement. The Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4 and the RAS-entity will be provided the results by the PC. The PC is the functional entity best suited to perform this evaluation because they have a wide-area planning perspective.

The drafting team disagrees that there will be any reliability impact during the transition period. The analyses required in Requirement R5 for all operations of the RAS will provide the reliability assurance you reference.

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Name:	IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Selected Answer: No

Answer Comment: Many Transmission Owner organizations also perform the transmission planning function and as such, are also registered as the Transmission Planners (for the assets that they own). The SRC believes that a proper, unbiased evaluation of RAS performance should be conducted by an entity that is not in the same organization as the TO and has a broader perspective, which is important because RAS's intended function and operational impact may affect more than one TO and TP. The SRC respectfully asserts that, given the importance of independence and a wide-area perspective, the Planning Coordinator is a more appropriate entity to perform Requirement R4 . The SRC therefore suggests replacing the TP with the PC or, at a minimum, requiring a review of results and provision of feedback by the Planning Coordinator to the Transmission Planner. This proposal is consistent with the basis for assigning R2 to the RC rather than the TOP.

Response: Thank you for your comment.

The drafting team revised the requirement. The Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4 and is required to provide the results of the RAS evaluation to each reviewing Reliability Coordinator and each impacted Transmission Planner and RAS-entity. The PC is the functional entity best-suited to perform this evaluation because they have a wide-area planning perspective.

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer:	Yes
Answer Comment:	See comment in no. 7.

Response: Please see the drafting team's response to the referenced comment.

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment: The RAS-entity would be more appropriate to be specified in R4 instead of the RAS-owner.

The RAS-entity and the RAS-owner should be provided with the result of the review. The PC may be more appropriately qualified to review certain RAS than the TP.

Response: Thank you for your comment.

The drafting team revised the requirement. The Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4 and is required to provide the results of the RAS evaluation to each reviewing Reliability Coordinator and each impacted Transmission Planner and RAS-entity. The PC is the functional entity best-suited to perform this evaluation because they have a wide-area planning perspective.

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments

Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: Yes

Answer Comment: Dominion suggests clarifying in R4 that the evaluation is a technical evaluation as stated below:

Each Transmission Planner shall perform a **technical** evaluation (planning analyses) evaluation of each RAS within its planning area at least once every 60-full-calendar-months and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies.

Response: Thank you for your comment.

The drafting team declines to make the suggested change.

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Selected Answer: No

Answer Comment: R4 should be modified to include a new part 4.5 that would require the Transmission Planner to identify any performance deficiencies in the RAS as well as alternatives for mitigating or correcting such deficiencies. The RAS-owners would not have the capability to identify alternatives for correcting deficiencies.

Response: Thank you for your comment.

The drafting team revised the requirement to make the Planning Coordinator (PC) the responsible entity for performing the periodic evaluations and requiring the PC to provide the results of the RAS evaluation to each reviewing Reliability Coordinator and each impacted Transmission Planner and RAS-entity.

Requirements R6 mandates the RAS-entity develop a Corrective Action Plan. If the RAS-entity needs assistance, it can engage its Transmission Planner or Planning Coordinator. The drafting team declines to make your suggested change.

Likes: 4

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5

Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Selected Answer:	No
Answer Comment:	It would be more appropriate to specify the RAS-entity in R4 instead of the RAS-owner. The RAS-entity and the RAS-owner should be provided with the results of the review. The PC may be more appropriately qualified to review certain RAS than the TP. Consider revising R4 to read “Each Transmission Planner shall evaluate…” Add wording to the Rationale for Requirement R4 to clarify that the intent is not to evaluate all RAS at the same time, but that each RAS is to be evaluated on a 60 full calendar month cycle. Would the Planning Coordinator ever perform this evaluation instead of the Transmission Planner?

Response: Thank you for your comment.

The drafting team revised the requirement. The Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4 and is required to provide the results of the RAS evaluation to each reviewing Reliability Coordinator and each impacted Transmission Planner and RAS-entity. The PC is the functional entity best-suited to perform this evaluation because they have a wide-area planning perspective. Please see the complementary revisions to the Rationale boxes and Supplemental Material section of the draft standard.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Answer Comment: ERCOT supports the comments submitted by the ISO/RTO Council.

Response: Please see the drafting team's responses to the referenced comments.

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: No

Answer Comment: PJM supports the comments submitted by the ISO/RTO Council.

Response: Please see the drafting team's responses to the referenced comments.

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: No

Answer Comment: How would a scenario be addressed in which a RAS spans two or more Transmission Planner areas?

Response: Thank you for your comment.

The drafting team revised the requirement to make the Planning Coordinator (PC) the responsible entity for performing the periodic evaluations. The drafting team notes that the existing wording of the requirement allows the individual PCs to perform the evaluation of RAS within its own planning area, and also allows coordination of all relevant PCs to perform a joint evaluation of RAS that span multiple PC areas. The PC is the functional entity best suited to perform this evaluation because they have a wide-area planning perspective.

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer: No

Answer Comment: TANC has concerns with the current language in R4 because appears to assume that a RAS exists within a single planning area. NERC has not defined the term "planning area", which creates ambiguity in the requirement's language that states "Each Transmission Planner shall perform an evaluation of each RAS within its planning area." This ambiguity is further compounded in circumstances where a single RAS exists within the footprints of multiple Transmission Planners (and

	Planning Coordinators). In such cases, it is unclear which Transmission Planners associated with the multiple RAS-owners for a single RAS would have responsibility in accordance with this standard.

Response: Thank you for your comment.

The drafting team revised the requirement to make the Planning Coordinator (PC) the responsible entity for performing the periodic evaluations. The drafting team notes that the existing wording of the requirement allows the individual PCs to perform the evaluation of RAS within its own planning area, and also allows coordination of all relevant PCs to perform a joint evaluation of RAS that span multiple PC areas.

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:	No
Answer Comment:	We generally agree with the process outlined by R4, but reiterate our comment that the Planning Coordinator, NOT the TP, should the entity responsible for this requirement. Many Transmission Owner organizations also perform the transmission planning function and as such, are also registered as the Transmission Planners (for the assets that they own). A proper and unbiased evaluation of the RAS performance should be conducted by an entity that is not in the same organization as the TO and has a wider perspective than the TO and TP. And since the RAS intended function its operational impact may affect more than one TOs and TPs, a PC is the

most appropriate entity to perform this task than the TP, both from an independence and a wide area perspectives. We therefore suggest replacing the TP with the PC. This proposal is consistent with the basis for assigning R2 to the RC rather than the TOP.

The RAS-entity and the RAS-owner should be provided with the result of the review. The PC may be more appropriately qualified to review certain RAS than the TP.

Response: Thank you for your comment.

The drafting team revised the requirement. The Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4 and is required to provide the results of the RAS evaluation to each reviewing Reliability Coordinator and each impacted Transmission Planner and RAS-entity. The PC is the functional entity best-suited to perform this evaluation because they have a wide-area planning perspective.

Richard Vine - California ISO - 2 -

Selected Answer: No

Answer Comment: The California ISO supports the comments of the ISO/RTO Standards Review Committee

Response: Please see the drafting team's responses to the referenced comments.

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Dixie Wells - Lower Colorado River Authority - 5 -

Group Name: LCRA Compliance

Group Member Name	**Entity**	**Region**	**Segments**
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Selected Answer: No

Answer Comment: To address existing entity NERC registration in the ERCOT region, “Transmission Planner” should be replaced with “Transmission Planner (in the ERCOT Region this applies to the Planning Authority and /or

Reliability Coordinator.)"

R4. Each Transmission Planner (in the ERCOT Region this applies to the Planning Authority and /or Reliability Coordinator) shall perform an evaluation of each RAS within its planning area at least once every 60-full-calendar-months and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Response: Thank you for your comment.

The drafting team revised the requirement. The Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4 and is required to provide the results of the RAS evaluation to each reviewing Reliability Coordinator and each impacted Transmission Planner and RAS-entity. The PC is the functional entity best-suited to perform this evaluation because they have a wide-area planning perspective.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2

Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Selected Answer: Yes

Answer Comment: We feel that the Transmission Planner also conducting an analysis will help address changes to the RAS which could impact the BES. Additionally, we like the fact that the analysis can be performed earlier if changes to the systems topology or system operating conditions has a potential impact on the BES (as mentioned in the second paragraph of the Rationale Box for Requirement R4).

Response: Thank you for your comments.

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer:	Yes

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer:	Yes

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:	No
Answer Comment:	Texas RE asks the drafting team to consider adding the Planning Coordinator to Requirement R4 for instances where a RAS covers multiple Transmission Planner areas. The current practice the ERCOT region is ERCOT conducts the 5-year review of each RAS; however, ERCOT is the Planning Coordinator, not a Transmission Planner. Texas RE asks the drafting about the term “60-full-calendar-months” in Requirements R4 and R6. The term is not defined and is not consistent with other standards and requirements. PRC-006 indicates five years, PRC-010-1 indicates 60 calendar months, and PRC-014 indicates five years. Texas RE recommends not introducing new terms and to be as consistent as possible. Is the SDT defining a “full calendar month” or

"calendar year"? The RSAW is not the place to define a new term and the definition is different than terms used in PRC-005. This definition is misleading to those reviewing the document and could potentially exacerbate reliability issues nearly seven years based on the "definition" provided in the Note to Auditor section of R4 in the RSAW.

The intent of Requirement R9 should be to update once per year not once per 729 days (2 years minus 1 day) which would be allowable by the definition of full calendar year as stated in the RSAW.

Texas RE recommends defining the term "planning area". It should be prescriptive enough to include GOs and DPs that are RAS-owners, i.e. generator owners or distribution providers that own all or part of a RAS. In Requirement R4, by default a Generator Owner or Distribution Provider owned RAS would be within a Transmission Planners planning area, correct? Please confirm or give specifics as to why a GO or DP owned RAS would not be within a Transmission Planners planning area.

Response: Thank you for your comment.

The drafting team revised the requirement. The Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4 and is required to provide the results of the RAS evaluation to each reviewing Reliability Coordinator and each impacted Transmission Planner and RAS-entity. The PC is the functional entity best-suited to perform this evaluation because they have a wide-area planning perspective.

The drafting team uses the clarifier "full" to be clear that partial months are not counted. For example, if the starting point is in the middle of a calendar month, the entity will have until the end of the last month of the stated period.

The drafting team revised the language to "at least once every 12-full calendar months".

The drafting team maintains that the term “planning area” is generally understood throughout the industry and declines to attempt to define it in this standard.

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Selected Answer: No

Answer Comment: The RAS owner must review the RASs in R4, R5, R6. Nowhere does it give the reviewing Reliability Coordinator the authority to dispute the evaluation in R4, dispute the analysis in R5, and require changes to the corrective action plan in R6. RC is just provided the results of analysis but is not given any authority to do anything with them.

Response: Thank you for your comment.

The drafting team agrees that the Reliability Coordinator is provided the results of the requirements you mention and the drafting team maintains that is sufficient. The Reliability Coordinator is already responsible for the reliability of its RC Area and has the authority to address any reliability concern through other standards.

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment: Although Hydro One Networks Inc. agrees with the evaluation process, we emphasize (as described above in Q1) that the evaluation of each new RAS must also be required from the TP or PC before the RAS is approved and implemented by the RAS owner/entity. We recognize that it is inconsistent to require the initial assessment of a RAS from a RAS owner/entity (in R1), and the subsequent/periodic assessments from a TP (in R4).

Response: Thank you for your comment.

The drafting team acknowledges that the need for a RAS and/or the determination of RAS characteristics are most often identified through planning studies performed by the Planning Coordinators or Transmission Planners. These studies are included in the Attachment 1 information supplied to the Reliability Coordinator (RC) for the RAS review and approval. Consequently, the drafting team contends that mandating the Planning Coordinator to participate in the RAS approval process is unnecessary and declines to make the suggested change. As the drafting team stated in the Rationale and Supplemental Materials section of the standard, the RC has the “flexibility” to request information or assistance from relevant entities (third parties) to participate in the review if they believe it will enhance the quality and efficiency of the review process. The ability of the RC to solicit assistance in performing the RAS review does not indicate that the RC is not equipped to perform the RAS review, or that another party should be chosen to perform the review. To the contrary, this flexibility allows the RC to perform a more robust review.

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer: Yes

Answer Comment: Recommend changing 60 full calendar months to 5 calendar years, to allow the RAS evaluation to fit within the annual Planning Assessment process which may vary from year to year.

Response: Thank you for your comment.

The drafting team based the 60 full calendar months schedule on the existing PRC-014-0, Requirement R1 to perform an assessment "at least once every five year. . ." The drafting team does not see a convincing reliability reason to further extend this schedule and declines to make the suggested change.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5

John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Selected Answer: No

Answer Comment:

(1) We believe 60 calendar months is an appropriate amount of time to conduct RAS periodic evaluations. However, we do not believe the TP has sufficient visibility outside of its area to determine if the BES will remain stable or the occurrence of a Cascading outage will be minimized following the inadvertent operation of a RAS from any single RAS component malfunction. These “wide-area” views are only available to the PC. We believe the requirement should be rewritten to include the PC as an applicable entity for these technical evaluations.

(2) We have concerns that the requirement does not identify what events will trigger when the clock begins on the 60 calendar month timeframe. We ask the SDT to clarify when the clock starts for these periodic evaluations – is it after the initial installation, after the latest modification to RAS functionality, or following a response to a CAP?

Response: Thank you for your comments.

Based on comments, the drafting team revised the requirement. The Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4 and is required to provide the results of the RAS evaluation to each reviewing Reliability Coordinator and each impacted Transmission Planner and RAS-entity. The PC is the functional entity best-suited to perform this evaluation because they have a wide-area planning perspective.

For existing RAS, the initial performance of the requirement must be completed within 60 full calendar months of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within sixty full calendar months of the RAS approval date by the reviewing RC(s). The drafting team added language to the Implementation Plan to provide additional clarity.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

3. RAS Inadvertent Operation: Do you agree with Requirement 4 Part 4.3 and Attachment 1 which stipulates that RAS inadvertent operation due to a single component malfunction still satisfies the System performance requirements common to TPL-001-4 P1-P7 events listed in Parts 4.3.1-4.3.5? (Note that this requirement remains the same as PRC-012-0 R1.4 except for the allowance for designed-in security that would prevent RAS inadvertent operation for any single component malfunction). If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:	Yes

Thomas Foltz - AEP - 5 -

Selected Answer:	No
Answer Comment:	Clarity is needed in R4 as to exactly what the trigger is for the 60-full-calendar-months periodic review. Is it tied, perhaps, to the in-service status? In addition, rather than a 60 full month periodic review, AEP suggests a “5 calendar year” review. This would allow flexibility for an entity to integrate this work into its annual planning cycle.

Response: Thank you for your comment.

The initial performance of the evaluation must be completed within 60 full calendar months of the effective date of PRC-012-2. The successive performances are triggered by the previous evaluation date. The drafting team added language to the Implementation Plan, rationale box, and Supplemental Material section of the standard to provide additional clarity. The drafting team does not see any benefit in your suggestion and declines to make the change.

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6

Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: Yes

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Selected Answer: No

Answer Comment: Needs further clarification. The Transmission Planner or the group that *owns* the RAS should be responsible for the evaluation, coordination and testing of the RAS.

Response: Thank you for your comment.

The drafting team revised the requirement and the Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4. The drafting team agrees that the RAS-entity may need to be contacted by the PC. The PC is the functional entity best suited to perform this evaluation because they have a wide-area planning perspective.

Chris Scanlon - Exelon - 1 -

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Selected Answer: Yes

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: Yes

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: No

Answer Comment: Recommend deleting Part 4.3 since we find it hard to conceive how the inadvertent operation of RAS can result in unacceptable system performance when the primary motivation for installing any RAS is to achieve acceptable system performance. We acknowledge that inadvertent RAS operation is undesirable, but we also recognize that it is fundamentally the same as a RAS misoperation. And therefore, any adverse reliability impact due to inadvertent RAS operation would get addressed in R5 during RAS operational performance analysis. Consequently, we do not see any reliability risk, and thus no associated compelling need, to identify the potentially unacceptable system performance based on simulations/analyses performed for periodic RAS evaluation using models that reflect "typical" rather than actual operating conditions. Although we agree with the goal of a robust RAS design that is not susceptible to RAS misoperation caused by the malfunction of a single component, we also believe this objective is effectively accomplished by any corrective action plan spawned by the RAS operational performance analysis in R5.

Response: Thank you for your comment.

The drafting team maintains that it is desirable from a reliability perspective to identify potential inadvertent operation issues in Requirement R4 rather than waiting for an incorrect operation to occur to determine whether actual System performance was unacceptable. RAS operation when applicable system conditions are not present may degrade system performance or pose a risk to reliability. For example, a RAS designed to shed a certain amount of load following a loss of generation can lead to overfrequency on the System or other issues if the load is shed without the loss of generation actually occurring. The drafting team maintains it is better to be proactive rather than reactive from a reliability perspective and declines to make the suggested change.

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment: Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Response: Please see the drafting team’s responses to the referenced comments.

David Greene - SERC - 1,10 - SERC

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Selected Answer: Yes

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: No

Answer Comment: Part 4.3 addresses inadvertent operation and addresses security of the RAS. This is important however and we suggest that only 4.3.1 and 4.3.2 as well as controlling system separation are the only aspects that are needed. In Attachment 2 we agree that inadvertent operation needs to be understood however if that inadvertent operation does not cause one of the three significant adverse impacts to the reliability of the BES then the RAS should not be subject to additional requirements which likely will only have a localized effect. The addition of this language in R 4.3.3, 4.3.4, and 4.3.5 unnecessarily may result in local RAS to have increased design complexity, additional components which may increase the likelihood of misoperation (decreasing the reliability of the RAS) and excessive costs. We suggest the SDT consider that all RAS which have a wider impact, whose inadvertent operation could result in Cascading, System Separation or instability be subject to this standard and its design requirements. To place these requirements as written on all RAS would be of little or no benefit to achieving an adequate level of reliability on the BES and based on this we would characterize this as placing a requirement such as those removed by Paragraph 81 in the standard. Furthermore, this could actually be a detriment to the reliable operation of a local RAS subjecting it to unnecessary additional design requirements.

Response: Thank you for your comment.

The drafting team included a provision that RAS can be designated as “limited impact” if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process.

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer:	Yes
Answer Comment:	Consider adding 4.3.6 “Frequency Trigger Limits (FTLs) shall be within acceptable limits as established”

Response: Thank you for your comment.

The drafting team contends that frequency trigger limits are only relevant in Reliability Standard BAL-001-2 and declines to make the suggested change.

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Selected Answer: No

Answer Comment: Part 4.3 addresses inadvertent operation and addresses security of the RAS. This is important; however, we suggest that 4.3.1, 4.3.2, and controlling system separation should be the only aspects that are needed. We do not understand the intent of 4.3.3 “applicable facility ratings.” Is this normal, emergency, DAL (drastic action limit), etc.? In Attachment 2, we agree that inadvertent operation needs to be understood however if that inadvertent operation does not cause one of the three significant adverse impacts to the reliability of the BES, then the RAS should not be subject to additional requirements when the inadvertent operation likely will only have a localized effect. The addition of this unnecessary language in R 4.3.3, 4.3.4, and 4.3.5 may result in local RAS having increased design complexity, additional components that may increase the likelihood of misoperation (decreasing the reliability of the RAS) and excessive costs. We suggest the SDT consider that all RAS that have a wider impact, whose inadvertent operation could result in Cascading, System Separation, or instability, be subject to this standard and its design requirements. To place these requirements as written on all RAS would be of little or no benefit to achieving an adequate level of reliability on the BES and based on this we would characterize this as a Paragraph 81 requirement in the standard. Furthermore, this could actually be a detriment to the reliable operation of a local RAS, subjecting it to unnecessary additional design requirements.

Response: Thank you for your comment.

The drafting team included a provision that RAS can be designated as “limited impact” if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Selected Answer: Yes

Mike Smith - Manitoba Hydro - 1 -	
Selected Answer:	Yes
Erika Doot - U.S. Bureau of Reclamation - 5 -	
Selected Answer:	Yes
Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -	
Selected Answer:	Yes
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -	
Group Name:	IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Selected Answer: Yes

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment: See comment in no. 7.

Response: Please see the drafting team’s response to the referenced comment.

Mark Kenny - Eversource Energy - 3 -

Selected Answer:	No
Answer Comment:	Part 4.3 addresses inadvertent operation and addresses security of the RAS. This is important however we suggest that only 4.3.1 and 4.3.2 as well as controlling system separation are the only aspects that are needed. We do not understand the intent of 4.3.3 “applicable facility ratings”. Is this normal, emergency, DAL (drastic action limit), etc.? In Attachment 2 we agree that inadvertent operation needs to be understood however if that inadvertent operation does not cause one of the three significant adverse impacts to the reliability of the BES then the RAS should not be subject to additional requirements which likely will only have a localized effect. The addition of this language in R 4.3.3, 4.3.4, and 4.3.5 unnecessarily may result in local RAS to have increased design complexity, additional components which may increase the likelihood of misoperation (decreasing the reliability of the RAS) and excessive costs. We suggest the SDT consider that all RAS which have a wider impact, whose inadvertent operation could result in Cascading, System Separation or instability be subject to this standard and its design requirements. To place these requirements as written on all RAS would be of little or no benefit to achieving an adequate level of reliability on the BES and based on this we would characterize this as placing a Paragraph 81 requirement in the standard. Furthermore, this

could actually be a detriment to the reliable operation of a local RAS subjecting it to unnecessary additional design requirements.

Response: Thank you for your comment.

The drafting team included a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process.

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: No

Answer Comment: Dominion concurs with the idea of an inadvertent operations test; however R4.3.5 transient voltage response should not be part of that test. Preventing FIDVR is only necessary to prevent cascading due to motor stalling (an unlikely outcome) which is addressed under R4.3.2. Dominion believes that slow transient voltage response that does not lead to cascading and is a customer power quality issue and not a reliability issue.

Response: Thank you for your comment.

The drafting team disagrees with your comment. Requirement R4, Part 4.1.3.5 regarding transient voltage response is a performance requirement common to other TPL contingencies (P1 to P7), and does not apply only to FIDVR phenomena but any type of transient behavior that may affect stability.

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1

Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Answer Comment: No comment.

Likes: 4

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segment
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3

Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1

Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1

Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Selected Answer: No

Answer Comment: Part 4.3 addresses inadvertent operation and addresses security of the RAS. This is important. However, we suggest that only sub-Parts 4.3.1 and 4.3.2 as well as controlling system separation are the only aspects that are needed. We do not understand the intent of sub-Part 4.3.3 "applicable facility ratings". Is this normal, emergency, DAL (drastic action limit), etc.? In Attachment 2 we agree that inadvertent operation needs to be understood. However, if that inadvertent operation does not cause one of the three significant adverse impacts to the reliability of the BES then the RAS should not be subject to additional requirements which likely will only have a localized effect. The addition of this language in sub-Parts 4.3.3, 4.3.4, and 4.3.5 unnecessarily may result in local RAS to have increased design complexity, additional components which may increase the likelihood of misoperation (decreasing the reliability of the RAS) and excessive costs. We suggest the SDT consider that all RAS that have a wider impact, those whose inadvertent operation could result in Cascading, System Separation or instability be subject to this standard and its design requirements. To place these requirements as written on all RAS would be of little or no benefit to achieving an adequate level of reliability on the BES, and based on this we would characterize this as placing a Paragraph 81 requirement in the standard. Furthermore, this could actually be a detriment to the reliable operation of a local RAS subjecting it to unnecessary additional design requirements.

Response: Thank you for your comment.

The drafting team included a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment: ERCOT supports the comments submitted by the ISO/RTO Council.

Response: Please see the drafting team's responses to the referenced comments.

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:	Yes

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer:	Yes

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:	No
Answer Comment:	At the present time there are RAS in service that have a limited local impact. To universally apply the same design criteria to all RAS regardless of their impact on BES in case of an inadvertent operation may have no cost benefit in the case of the RAS installed to address local problems.

We propose the following to be included in the standard:

An inadvertent operation in the RAS, when the RAS is intended to operate, does not result in any of the following conditions on the BES:

1. Cascading

2. Uncontrolled System Separation

3. Instability

When the criteria mentioned above is not met a secure design will be required.

Response: Thank you for your comment.

The drafting team included a provision that RAS can be designated as “limited impact” if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process.

Richard Vine - California ISO - 2 -

Selected Answer: Yes

Answer Comment: The California ISO supports the comments of the ISO/RTO Standards Review Committee

Response: Please see the drafting team's responses to the referenced comments.

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Dixie Wells - Lower Colorado River Authority - 5 -

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Selected Answer: Yes

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Selected Answer: Yes

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Don Schmit - Nebraska Public Power District - 5 -	
Selected Answer:	Yes

Jeff Wells - Grand River Dam Authority - 3 -	
Selected Answer:	Yes

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:	Yes
Answer Comment:	The SDT may want to consider adding "Applicable System Operating Limits shall not be exceeded" as a sub-bullet to Requirement R4.3.

Response: Thank you for your comment.

The drafting team maintains that the Parts 4.1.3.1-4.1.3.5 are aligned with similar TPL performance requirements for contingencies P0-P7 as well as SOLs calculated for both the planning and operating horizons. The drafting team declines to make the suggested change.

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Selected Answer: Yes

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3

Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer: No

Answer Comment: FMPA agrees with the intent of R4.3 – that construction of devices/systems as an integral part of the BES should be held to same standards as construction of physical facilities. However, we believe there is a problem with the wording of the first sentence. It is possible to read the first sentence to be requiring that inadvertent operation of the RAS due to a single component malfunction be studied as a planning event regardless of whether the system is designed to prevent such an event from occurring. FMPA believes the intent of the language is that items 4.3.1 through 4.3.5 only apply if single component malfunction does actually produce an operation of the RAS. If this were not true (e.g. if the language in R4.3 was requiring the study of the inadvertent RAS operation against the criteria in 4.3.1 through 4.3.5 regardless of whether a single component malfunction could actually cause the RAS to operate), the language would essentially be requiring that TPL-001-4 Planning Event criteria be applied to what amounts to an Extreme Event. This is partly because of the use of the term “malfunction” as opposed to “failure”. This is not consistent with TPL-001-4 which refers to protection system “failures”. This is an important distinction because typically protection systems are designed such that if a component fails, it does so without issuing a false trip. A malfunction can be interpreted to mean a large number of absurdly unlikely things which are over and above the level of rigor required by TPL-001-4. FMPA understands that the SDT desired to consider the use of non-“protection system” control devices using this standard, but the language as written does not allow those entities that are using protective devices to take credit for basic design principles such as redundancy. Suggest either expressly allowing entities to take credit for redundancy, switching to using the term “failure” or both.

Response: Thank you for your comment.

The drafting team agrees with the intent of the comment - that 4.1.3.1-4.1.3.5 only apply if a single component malfunction, per the design of the RAS, can produce an inadvertent operation of the RAS (or part of the RAS). The drafting team maintains that there are other modes of improper component operation that the term “failures” may not clearly address, and therefore “malfunction” is a more appropriate term. Requirement R4, Part R4.1.3 maintains consistency with existing PRC-012-1 Requirement R1, R1.4 regarding inadvertent operation but is meant to clarify that design considerations to improve security can be implemented that will essentially prevent inadvertent operation. If single component malfunction (or failure) cannot cause an inadvertent operation, 4.1.3.1-4.1.3.5 do not need to be assessed.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Selected Answer: No

Answer Comment: Certain aspects of the TPL-001-4 P1-P7 events identify actions under a steady state or a stability assessment. We have concerns that applicable Facility Rating exceedances and BES voltages deviations, as identified with TPL-001-4, are only applicable under steady state conditions. We recommend the SDT modify Requirement R4 to identify these references within the context of a steady state assessment, instead of a transient state, to align with existing NERC standards.

Response: Thank you for your comment.

The drafting team agrees that applicable Facility Rating and BES voltage deviations, as identified with TPL-001-4 are applicable under steady-state conditions rather than transient conditions. However, for the purpose of the evaluation required in Requirement R4, Part 4.1.3 (Parts 4.1.3.1-4.1.3.5), RAS inadvertent operation needs to be assessed with regards to both the transient stability and steady-state performance requirements of TPL-001-4 P1-P7 (as for any TPL contingency). The drafting team declines to make the suggested change.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

4. RAS Single Component Failure: Do you agree with Requirement 4 Part 4.4 and Attachment 1 which stipulates that any RAS intended to satisfy System performance requirements in a TPL standard must still satisfy those requirements when experiencing a single component failure? (Note that this requirement remains unchanged from PRC-012-0 R1.3.) If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5

Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: No

Answer Comment: The NSRF recommends two modifications to Part 4.4.:

One modification is to explicitly include “option c” in the Implementation section of the Supplemental Material associated with the Standard. The revised wording could be, “A single component failure in RAS, when the RAS is intended to operate, or alternative automatic actions back up the failures of single RAS components . . .” Including text about the alternative option in the standard, rather than the Supplemental Material would assure that it cannot be dismissed by an auditor.

The other modification is to remove the unnecessary linking of R4.4 to TPL-001-4 performance requirements with linking to the performance requirements already expressed in R4.3 of PRC-002-2. The revised wording could be, “. . . satisfies the same performance criteria given in Part 4.3”. This change makes the performance requirements of Part 4.3 and Part 4.4 consistent with each other and subject to changes in the PRC-012-2, rather than independent changes in another NERC standard.

Response: Thank you for your comments.

The drafting team maintains that the alternative automatic actions described in the Attachment 1 (Supplemental Material) are examples of how the standard requirement can be met. The standard is not prescriptive in dictating the “how” to achieve the reliability objectives. The language of Requirement 4, Part 4.1.4 does not preclude any of the options ‘a’ through ‘d’ from being applied. As long as the relevant TPL standard performance requirements are satisfied, Part 4.1.4 is met. The drafting team declines to make the suggested change.

The intent of Requirement 4, Part 4.1.4 is to ensure the RAS satisfies all of the performance requirements specified in the TPL standard (which are more than those listed in Part 4.1.3) with regards to single component failure. Furthermore, the drafting team contends that the reference to the TPL standard is necessary to differentiate between RAS installed for meeting planning event performance requirements and those installed for extreme events. The drafting team declines to make the suggested change.

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Selected Answer: Yes

Chris Scanlon - Exelon - 1 -

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Selected Answer: Yes

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: Yes

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: No

Answer Comment: We do not agree that the "single component failure" requirement should apply to **all** RAS installed to satisfy TPL performance requirements, by completely disregarding the severity of adverse system impact resulting from the RAS failure to operate. In other words, we are advocating that due regard be given to the RAS classifications/types existing in NPCC, WECC and TRE regions, as well as the recommended RAS/SPS classifications in the SAMS-SPCS white paper. Using the RAS nomenclature proposed in the white paper, we recommend that the “single component failure” requirement be limited to Type PS (Planning Significant) schemes only. Excluding the Type PL schemes, like the accepted exclusion for “safety net” (Type ES/EL) schemes, does not necessarily compromise Adequate Level of Reliability in the BES. We recognize that this approach will require judicious selection of the demarcation criteria between Significant (Wide Area) versus Limited (Local) schemes – however, the existing NPCC and/or WECC demarcation criteria may serve as a reasonably good starting point. Lastly, we disagree with the claim that Part 4.4 remains unchanged from the existing R1.3 in PRC-012-0 – although both may have essentially the same verbiage, the context and the scope of applicability are widely different. While the existing R1.3 may be rightly interpreted to allow discretion to the RRO to determine which RAS/SPS “Types” must be subject to the more robust design that is not degraded by “single component failure”, Part 4.4 takes away that discretion by virtue of being a continent-wide standard. There is no factual evidence to suggest that the failure-to-operate of any Local/Limited RAS has resulted in unacceptable/adverse BES performance to warrant “raising the bar” on applicability of “single component failure” requirement.

Response: Thank you for your comment.

The drafting team included a provision that RAS can be designated as “limited impact” if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of this standard that has been through the regional review process and designated as Type 3 in NPCC, Type 2 in ERCOT, or LAPS in WECC will be recognized as limited impact. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process.

Molly Devine - IDACORP - Idaho Power Company - 1 - **Selected Answer:** Yes
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC **Selected Answer:** Yes
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC **Selected Answer:** No **Answer Comment:** Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports. **Response:** Please see the drafting team’s responses to the referenced comments.

David Greene - SERC - 1,10 - SERC

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Selected Answer: Yes

Answer Comment: Suggest adding clarity to indicate the intent of R4 is not to evaluate the performance of the RAS "following" an inadvertent operation since this is covered by R5. The below statement from the rationale for R4 can be misinterpreted to imply R4 requires the Transmission Planner to perform a technical evaluation "following" an inadvertent operation.

Copied from Rationale for R4:
The purpose of a periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that requirements for BES performance following an inadvertent RAS operation or a single component failure in the RAS continues to be satisfied.

Response: Thank you for your comment.

The drafting team agrees and revised the Requirement R4 rationale sentence as follows: “The purpose of a periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that, if a RAS single component failure or single component malfunction were to occur, requirements for BES performance would continue to be satisfied.”

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:	No
Answer Comment:	ATC recommends two modifications to Part 4.4. One modification is to explicitly include “option c” in the Implementation section of the Supplemental Material associated with the Standard. The revised wording could be, “A single component failure in RAS, when the RAS is intended to operate, or alternative automatic actions back up the failures of single RAS components . . .” Including text about the alternative option in the standard, rather than the Supplemental Material would assure that it cannot be dismissed by an auditor. The other modification is to remove the unnecessary linking of R4.4 to TPL-001-4 performance requirements with linking to the performance requirements already expressed in R4.3 of PRC-002-2. The revised wording could be, “. . . satisfies the same performance criteria given in Part 4.3”. This

	change makes the performance requirements of Part 4.3 and Part 4.4 consistent with each other and subject to changes in the PRC-012-2, rather than independent changes in another NERC standard.

Response: Thank you for your comments.

The drafting team maintains that alternative automatic actions described in the Attachment 1 supplemental material are examples of how the standard requirement can be met. The standard is not prescriptive in dictating the “how” to achieve the reliability results. The language of Requirement 4, Part 4.4 does not preclude any of the options ‘a’ through ‘d’ from being applied. As long as the relevant TPL standard performance requirements are satisfied, Part 4.4 is met. The drafting team declines to make the suggested change.

The intent of Requirement 4, Part 4.4 is to ensure the RAS satisfies all of the performance requirements specified in the TPL standard, which are more than those listed in Part 4.3, with regards to single component failure. The drafting team also contends that the reference to the TPL standard is necessary to differentiate between RAS installed for meeting planning event performance requirements and those installed for extreme events. The drafting team declines to make the suggested change.

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer:	No
Answer Comment:	Requirement R4 Part 4.4 is problematic for a number of reasons. First, placing this requirement on the Transmission Planner does not conform to the responsibilities or abilities of the Transmission Planner. While the TP may have some familiarity with the design of the RAS or with the Operating

Procedures which may be in place, it does not know or need to know the specifics of a single component failure, just the ramification of an overall RAS operation failure or inadvertent operation. Currently, the unapproved standard PRC-012-0 and -1 R1.3 contains a single component failure design requirement which is currently unapproved by FERC and the applicable governmental authorities in Canada. When these standards were approved by the NERC BOT there was no NERC BES definition nor was there an approved definition of what a RAS is. We believe that had the full implication of the costs to be borne by the industry been recognized and subsequent minimal or no reliability benefit associated with meeting that requirement for local impact only schemes, the standard would not have been approved. Further, the System Protection Coordination Subcommittee of NERC had specifically noted and suggested that 4 types of RAS are on the BES. Two of these were local and these categories were developed to afford the SDT to tailor specific and appropriate reliability and security requirements on these local type schemes. To broadly apply these more stringent requirements to all RAS on the new BES with the new RAS definition has little cost benefit. In addition, the existing PRC-012-0 and -1 only require a single component failure review and design requirement at the time of review. PRC-014-0 and -1, which are the SPS/RAS assessment standards currently do not require the Transmission Planner to include a requirement such as Requirement R4 Part 4.4 in their periodic assessment.

The regions should each have a process for ensuring the reliability of the BES and that the necessary level of reliability and security had been met at the time of approval. Furthermore, misoperations studies have not indicated that there is a reliability need to incorporate single component failure design into local systems. These local RAS which do not meet the requirement would need to be redesigned, outages taken and then have their revisions made to come into compliance. This, in and of itself would represent a risk to the operation and reliability of the BES.

Requirement R4 Part 4.4 currently states;

“4.4 A single component failure in the RAS, when the RAS is intended to operate, does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed.”

We suggest Part 4.4 be removed. However, if the SDT is unwilling to remove it we would propose the following:

4.4 A single component failure in the RAS, when the RAS is intended to operate,

does not result in any of the following conditions on the BES:

- Cascading
- Uncontrolled System Separation
- Instability

The above modification would provide the necessary level of security and reliability to the BES. Ensuring that RAS installed on the BES or to meet TPL requirements would only be required when the RAS operation is critical and any inadvertent operation results in a significant impact to the BES.

Response: Thank you for your comments.

The drafting team revised Requirement 4 to make the Planning Coordinator (PC) the responsible entity. The drafting team maintains that the PC does not need to know the detailed RAS design and can consult with the RAS-entity to ascertain the consequences of any single component failure. The drafting team maintains that the PC is the proper entity to perform the System performance evaluations listed in Requirement 4, Parts 4.1 through 4.4. The revisions to Requirement 4, Part 4.4 have effectively limited the number of RAS to be evaluated for single component failure and the amount of associated data the PC will need to obtain to perform the evaluation.

The drafting team agrees in principle with your comment and has revised Requirement 4, Part 4.4 to allow the Reliability Coordinator to determine whether a RAS has a "limited impact" and can therefore be exempted from Part 4.4 of the requirement. The drafting team also added an explanatory footnote and revised Attachments 1 and 2 to reflect the change in Part 4.4.

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment: Please affirm this understanding: For single component failure, a RAS must still satisfy System performance requirements.

Response: Thank you for your comments.

The drafting team agrees with your comment. Please see the revised Requirement 4, Part 4.4 which no longer applies to limited impact RAS.

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Selected Answer:	No
Answer Comment:	Requirement R4 Part 4.4 is problematic for a number of reasons. First, placing this requirement on the Transmission Planner does not conform to the responsibilities or abilities of the Transmission Planner. While the TP may have some familiarity with the design of the RAS or with the Operating Procedures in place, they do not know or need to know the specifics of a single component failure. The TP just needs to know the ramifications of an overall RAS operation failure or inadvertent operation. Currently, standards PRC-012-0 and PRC-012-1 R1.3 contain a single component failure design requirement. When these standards were approved by the NERC BOT, there was no NERC BES definition nor was there an approved definition of a RAS. We believe that had the full implication of the costs to be borne by the industry and the subsequent minimal or no reliability benefit associated with this (local impact only schemes) had been recognized, the standard would not have been approved by the NERC BOT. Further, the System Protection Coordination Subcommittee of NERC had specifically noted and suggested that 4 types of RAS are on the BES. Two of these types were local and these categories were developed to allow the SDT to tailor specific and appropriate reliability and security requirements on these local type schemes. To broadly apply these more stringent requirements to all RAS on the new BES with the new RAS definition has no cost benefit. In addition, PRC-012-0 and PRC-012-1 only require a single component failure review and design requirement at the time of review. PRC-014-0 and PRC-014-1, which are the SPS/RAS assessment standards, currently do not require the Transmission Planner to include a

requirement such as Requirement R4 Part 4.4 in their periodic assessment. The SDT has gone, in our view, unnecessarily beyond the intent of the current standards in this regard.

In addition, it should be noted that all existing RAS have gone through regional reviews and been approved for implementation. These existing RAS may not have met the existing single component failure requirement due to the revision of the BES. The regions each have a process for ensuring the reliability of the BES and the necessary level of reliability and security has been met at the time of approval. Furthermore, misoperations studies have not indicated that there is a reliability need to incorporate single component failure design into local systems. These local RAS, which do not meet the requirement, would need to be redesigned, undergo outages, and then have revisions made to bring them into compliance. This, in and of itself would represent a risk to the operation and reliability of the BES.

Requirement R4 Part 4.4 currently states:

"4.4 A single component failure in the RAS, when the RAS is intended to operate, does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed."

We suggest Part 4.4 be removed. However, if the SDT is unwilling to remove it, we propose the following:

"4.4 A single component failure in the RAS, when the RAS is intended to operate, does not result in any of the following conditions on the BES:

- Cascading

• Uncontrolled System Separation
• Instability"

The above modification would provide the necessary level of security and reliability to the BES. This ensures that RAS installed on the BES or installed to meet TPL requirements would only be required to meet Part 4.4 when the RAS operation is critical and any inadvertent operation results in a significant impact to the BES.

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

Response: Thank you for your comments.

Based on other comments, the drafting team revised Requirement 4 to make the Planning Coordinator (PC) the responsible entity. The drafting team maintains that the PC does not need to know the detailed RAS design and can consult with the RAS-entity to ascertain the consequences of any single component failure. The drafting team maintains that the PC is the proper entity to perform the System performance evaluations listed in Requirement 4, Parts 4.1 through 4.4. The revisions to Requirement 4, Part 4.4 have effectively limited the number of RAS to be evaluated for single component failure and the amount of associated data the PC will need to obtain to perform the evaluation.

The drafting team agrees in principle with your comment and has revised Requirement 4, Part 4.4 to allow the Reliability Coordinator to determine whether a RAS has a "limited impact" and can therefore be exempted from Part 4.4 of the requirement. The drafting team also added an explanatory footnote and revised Attachments 1 and 2 to reflect the change in Part 4.4.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Selected Answer: Yes

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Selected Answer:	Yes
Answer Comment:	
Oliver Burke - Entergy - Entergy Services, Inc. - 1 -	
Selected Answer:	Yes
Answer Comment:	See comment in no. 7.
Response:	
Mark Kenny - Eversource Energy - 3 -	
Selected Answer:	No
Answer Comment:	Requirement R4 Part 4.4 is problematic for a number of reasons. First, placing this requirement on the Transmission Planner does not conform to

the responsibilities or abilities of the Transmission Planner. The TP, although may have some familiarity with the design of the RAS or with the Operating Procedures which may be in place does not know or need to know the specifics of a single component failure, just the ramification of an overall RAS operation failure or inadvertent operation. Currently, the unapproved standard PRC-012-0 and -1 R1.3 contains a single component failure design requirement which is currently unapproved by FERC and the applicable governmental authorities in Canada. When these standards were approved there was no NERC BES definition nor was there an approved definition of what a RAS is. We believe that had the full implication of the costs to be borne by the industry been recognized and subsequent minimal or no reliability benefit associated with meeting that requirement for local impact only schemes, the standard would not have been approved. Further, the System Protection Coordination Subcommittee of NERC had specifically noted and suggested that 4 types of RAS are on the BES. Two of these were local and these categories were developed to afford the SDT to tailor specific and appropriate reliability and security requirements on these local type schemes. To broadly apply these more stringent requirements to all RAS on the new BES with the new RAS definition has no cost benefit. In addition, the existing PRC-012-0 and -1 only require a single component failure review and design requirement at the time of review. PRC-014-0 and -1, which are the SPS/RAS assessment standards currently do not require the Transmission Planner to include a requirement such as Requirement R4 Part 4.4 in their periodic assessment. The SDT has gone, in our view, unnecessarily beyond the intent of the current standards in this regard.

In addition it should be noted that all existing RAS have gone through regional reviews and been approved for implementation. These existing RAS may not have met the existing single component failure requirement due to the revision of the BES. The regions each have a process for ensuring the reliability of the BES and that the necessary level of reliability and security had been met at the time of approval. Furthermore, misoperations studies have not indicated that there is a reliability need to incorporate single component failure design into local systems. These local RAS which do not meet the requirement would need to be redesigned, outages taken and then have their revisions made to come into compliance. This, in and of itself would represent a risk to the operation and reliability of the BES.

Requirement R4 Part 4.4 currently states;

"4.4 A single component failure in the RAS, when the RAS is intended to operate, does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed."

We suggest Part 4.4 be removed. However, if the SDT is unwilling to remove it we would propose the following:

4.4 A single component failure in the RAS, when the RAS is intended to operate,

does not result in any of the following conditions on the BES:

- Cascading
- Uncontrolled System Separation
- Instability

The above modification would provide the necessary level of security and reliability to the BES. Ensuring that RAS installed on the BES or to meet TPL requirements would only be required when the RAS operation is critical and any inadvertent operation results in a significant impact to the BES.

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

Response: Thank you for your comments.

The drafting team revised Requirement 4 to make the Planning Coordinator (PC) the responsible entity. The drafting team maintains that the PC does not need to know the detailed RAS design and can consult with the RAS-entity to ascertain the consequences of any single component failure. The drafting team maintains that the PC is the proper entity to perform the System performance evaluations listed in Requirement 4, Parts 4.1 through 4.4. The revisions to Requirement 4, Part 4.4 have effectively limited the number of RAS to be evaluated for single component failure and the amount of associated data the PC will need to obtain to perform the evaluation.

The drafting team agrees in principle with your comment and has revised Requirement 4, Part 4.4 to allow the Reliability Coordinator to determine whether a RAS has a “limited impact” and can therefore be exempted from Part 4.4 of the requirement. The drafting team also added an explanatory footnote and revised Attachments 1 and 2 to reflect the change in Part 4.4.

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: No

Answer Comment:

Dominion believes that redundancy should not be required for a RAS designed for events such as TPL-001-4 P4 (stuck breaker) or P5 (relay failure event). The design should not have to consider two failures which is improbable. As an analogy, in places where there is no RAS scheme, there is no requirement to test a P4 stuck breaker event and then assume that the breaker failure relay does not work, essentially combining P4 and P5 together. Designing a redundant RAS for breaker failure could require installation of two breaker failure relays per breaker to initiate the RAS and maintain complete redundancy. This leads to excessive complexity which can hurt reliability.

Additionally, Dominion suggest adding clarity to indicate the intent of R4 is not to evaluate the performance of the RAS "following" an inadvertent operation since this is covered by R5. The rationale statement for R4 can be misinterpreted to imply R4 requires the Transmission Planner to perform a technical evaluation **"following"** an inadvertent operation.

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

Response: Thank you for your comments.

The SDT agrees that a single component failure of a RAS during a P4 or P5 event has a low probability of occurrence. However, the SDT maintains that the single component failure requirement applies to contingencies in TPL-003 in the current standard. Not having the single component failure test apply to P4 or P5 events would be lowering the bar from the previous standard.

The SDT agrees and has revised the R4 rationale sentence as follows: "The purpose of a periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that, if a RAS single component failure or single component malfunction were to occur, requirements for BES performance would continue to be satisfied."

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Answer Comment: No comment

Likes: 4 PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable

Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6

Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1

Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Selected Answer: No

Answer Comment: Requirement R4 Part 4.4 is problematic for a number of reasons. First, placing this requirement on the Transmission Planner does not conform to the responsibilities or abilities of the Transmission Planner. The TP may have some familiarity with the design of the RAS or with the Operating Procedures which may be in place, but does not know or need to know the specifics of a single component failure, just the ramification of an overall RAS operation failure or inadvertent operation. Currently, Part R1.3 of standards PRC-012-0 and -1 contains a single component failure design requirement. When these standards were approved by the NERC BOT there was no NERC BES definition nor was there an approved definition of what a RAS is. We believe that had the full implication of the costs to be borne by the industry been recognized and subsequent minimal or no reliability benefit associated with meeting that requirement for local impact only schemes, the standard would not have been approved by the NERC BOT. Furthermore, the System Protection Coordination Subcommittee of NERC had specifically noted and suggested that 4 types of RAS are on the BES. Two of these were local and these categories were developed to afford the SDT to tailor specific and appropriate reliability and security requirements on these local type schemes. To broadly apply these more stringent requirements to all RAS on the new BES with the new RAS definition has little cost benefit. In addition, the existing PRC-012-0 and -1 only require a single component failure review and design requirement at the time of review. PRC-014-0 and -1, which are the SPS/RAS assessment standards currently do not require the Transmission Planner to include a requirement such as Requirement R4 Part 4.4 in their periodic assessment. The SDT has gone unnecessarily beyond the intent of the current standards in this regard.

In addition it should be noted that all existing RAS have gone through regional reviews and been approved for implementation. These existing RAS may not have met the existing single component failure requirement due to the revision of the BES. The regions each have a process for ensuring the reliability of the BES, and that the necessary level of reliability and security had been met at the time of approval. Furthermore, misoperation studies have not indicated that there is a reliability need to incorporate single component failure design into local systems. These local RAS which do not meet the requirement would need to be redesigned, outages taken, and then revisions made to come into compliance. This, in and of itself would represent a risk to the operation and reliability of the BES.

Requirement R4 Part 4.4 currently states;

"4.4 A single component failure in the RAS, when the RAS is intended to operate, does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed."

We suggest Part 4.4 be removed. However, if not removed, we propose the following:

4.4 A single component failure in the RAS, when the RAS is intended to operate, does not result in any of the following conditions on the BES:

- Cascading
- Uncontrolled System Separation
- Instability

The above modification would provide the necessary level of security and reliability to the BES. Ensuring that RAS installed on the BES or installed to meet TPL requirements would only be required when the RAS operation is critical, and any inadvertent operation results in a significant impact to the BES.

Response: Thank you for your comments.

The drafting team revised Requirement 4 to make the Planning Coordinator (PC) the responsible entity. The drafting team maintains that the PC does not need to know the detailed RAS design and can consult with the RAS-entity to ascertain the consequences of any single component failure. The drafting team maintains that the PC is the proper entity to perform the System performance evaluations listed in Requirement 4, Parts 4.1 through 4.4. The revisions to Requirement 4, Part 4.4 have effectively limited the number of RAS to be evaluated for single component failure and the amount of associated data the PC will need to obtain to perform the evaluation.

The drafting team agrees in principle with your comment and has revised Requirement 4, Part 4.4 to allow the Reliability Coordinator to determine whether a RAS has a "limited impact" and can therefore be exempted from Part 4.4 of the requirement. The drafting team also added an explanatory footnote and revised Attachments 1 and 2 to reflect the change in Part 4.4.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment: ERCOT supports the comments submitted by the ISO/RTO Council.

Response:

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: Yes

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: No

Answer Comment: Single component failures should exclude station dc supply and some portions of communications systems (e.g., microwave towers and multiplexing equipment). Such exceptions have existed in the industry.

For a single component failure, it is unclear why the requirement was changed from simply having to meet the performance requirements defined in TPL standards to having to meet those required for the events and conditions for which the RAS is designed.

In the Q & A document, section 5, page 4, how can arming excess load and generation not impact reliability? TPL footnote 9 notes that “the planning process should be to minimize the likelihood and magnitude of interruption.” RAS entities should be allowed to consider whether a 100% chance of tripping too much load/generation in the event of correct RAS operation really meets the intent of TPL. In some cases, allowing a single point failure to degrade the performance of the RAS is a better overall choice for minimizing total probability of interruption.

In the Q & A document, section 5, page 4, what kind of automatic actions are referenced? As the NERC reliability standards have evolved, the classification of RAS has expanded from just very high complexity protection schemes to now include many kinds of routine automatic actions. Almost any automatic action used to mitigate a TPL violation would become a RAS by virtue that it is used to meet requirements identified in a NERC Reliability Standard.

Response: Thank you for your comments.

The drafting team declines to identify RAS components that could be excluded from the single component failure aspect of the requirement. For new and modified RAS, single component failure design will be reviewed by the RC and any components subject to inclusion or exclusion will be determined at that time.

The drafting team used the words "meet those required for the events and conditions for which the RAS is designed" to be consistent with our understanding of the existing standard PRC-012-0. This also makes it clear that a RAS designed for an extreme event does not have to meet the performance requirements listed in the TPL standard.

Arming excess load and generation in a RAS is only allowed when tripping load or generation is allowed by TPL-001-4. If it is allowed by TPL-001-4, then it should not be affecting the reliability of the system (according to that standard). Allowing a single component failure to degrade the performance of the RAS may minimize the total probability of interruption. However, the RAS would have been designed and placed into service to solve some System performance issue. It is better to ensure that the System performance issue is satisfied for single component failures even if additional load or generation has to be armed for interruption.

Automatic actions may or may not be classified as a RAS. An example which would not be classified as a RAS would be a UVLS Program (consisting of only distributed relays) which is located in the same area as a RAS. The RAS was separately installed to solve a voltage problem in an area. The UVLS Program is not a RAS but the automatic action taken by the UVLS relays, assuming that load shedding is permissible for the event under the TPL standard, could provide the necessary relief if a single component of the RAS failed.

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:	No
Answer Comment:	At the present time there are RAS in service that have a limited local impact. To universally apply the same design criteria to all RAS regardless of their impact on BES in case of failure to operate may have no cost benefit in the case of the RAS installed to address local problems.

We propose the following to be included in the standard:

The failure of a RAS to operate does not result in any of the following conditions on the BES:

1. Cascading

2. Uncontrolled System Separation

3. Instability

When the criteria mentioned above is not met a redundant design will be required.

When a RAS is used to respond to an event, e.g. category P1 in TPL-001-4, its failure should be considered to be a more severe event, just as in TPL-001-4 the failure of a breaker or protection relay following a P1 event is recognized as “Multiple Contingency” (category P3 and P4). For this reason, the system performance with a RAS failure should not be required to meet the same requirements (defined in TPL-001-4) as those for the original event.

We suggest that the system performance requirement in case of failure of a single component of a RAS be limited to the following:

1. The BES shall remain stable

2. Cascading or Uncontrolled System Separation shall not occur

Response: Thank you for your comments.

The drafting team agrees in principle with your comment and has revised Requirement 4, Part 4.4 to allow the Reliability Coordinator to determine whether a RAS has a "limited impact" and can therefore be exempted from Part 4.4 of the requirement. The drafting team also added an explanatory footnote and revised Attachments 1 and 2 to reflect the change in Part 4.4.

The SDT agrees that a single component failure of a RAS during a P3 or P4 event has a low probability of occurrence. However, the SDT maintains that the single component failure requirement applies to contingencies in TPL-003 in the current standard. Not having the single component failure test apply to P3 or P4 events would be lowering the bar from the previous standard.

Richard Vine - California ISO - 2 -

Selected Answer:	Yes
Answer Comment:	The California ISO supports the comments of the ISO/RTO Standards Review Committee

Response: Please see the drafting team's responses to the referenced comments.

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Dixie Wells - Lower Colorado River Authority - 5 -

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Selected Answer: Yes

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Selected Answer: Yes

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Yes

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer:	Yes
Rachel Coyne - Texas Reliability Entity, Inc. - 10 -	
Selected Answer:	Yes
Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3	
Selected Answer:	Yes
Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -	
Selected Answer:	No
Answer Comment:	When a RAS is used to respond to an event, e.g. category P1 in TPL-001-4, its failure should be considered to be a more severe event, just as in TPL-001-4 the failure of a breaker or protection relay following a P1 event is recognized as "Multiple Contingency" (category P3 and P4). For this reason, the system performance with a RAS failure should not be required to meet the same

requirements (defined in TPL-001-4) as those for the original event.

We suggest that the system performance requirement in case of failure of a single component of a RAS be limited to the following:

1. The BES shall remain stable

2. Cascading or Uncontrolled System Separation shall not occur

Please also see the following comments for relaxing the requirements for a class of RAS.

Response: Thank you for your comments.

The drafting team revised Requirement 4 to make the Planning Coordinator (PC) the responsible entity. The drafting team maintains that the PC does not need to know the detailed RAS design and can consult with the RAS-entity to ascertain the consequences of any single component failure. The drafting team maintains that the PC is the proper entity to perform the System performance evaluations listed in Requirement 4, Parts 4.1 through 4.4. The revisions to Requirement 4, Part 4.4 have effectively limited the number of RAS to be evaluated for single component failure and the amount of associated data the PC will need to obtain to perform the evaluation.

The drafting team agrees in principle with your comment and has revised Requirement 4, Part 4.4 to allow the Reliability Coordinator to determine whether a RAS has a “limited impact” and can therefore be exempted from Part 4.4 of the requirement. The drafting team also added an explanatory footnote and revised Attachments 1 and 2 to reflect the change in Part 4.4.

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer: Yes

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Selected Answer: No

Answer Comment: We recommend that the SDT consolidate the numerous sub-parts in Requirement R4, as they are confusing to both registered entity and auditor.

Response: Thank you for your comment.

The subparts of Requirement R4 are distinct components of the evaluation that must be made. The drafting team maintains that attempting to consolidate them would reduce clarity, not improve it.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

5. Corrective Action Plans: Do you agree that the application of Requirements R6 and R7 would address the reliability objectives associated with CAPs? If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer: No

Answer Comment: We suggest that the RAS-owner be removed from the Requirements, and that only the RAS-entity be subject to these Requirements. See below for more comments.

Response: Thank you for your comment.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team contends that the RAS-entity as the asset owner, is in the best position to develop the actions and timelines necessary; i.e., schedule the work and submit clearances to perform the activities required to correct the deficiencies.

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment: AEP believes R6 should be further revised to clarify exactly when the “six calendar months” begins. We suggest revising it to state ”Within six-full-calendar months of *the RC* being notified of a deficiency…”

Response: Thank you for your comment.

The drafting team revised the requirement.

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments

Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: No

Answer Comment: The NSRF recommends revising R6 to explicitly include the Planning Coordinator with working like, “. . . submit the CAP to its reviewing Reliability Coordinator and impacted Transmission Planners and Planning Coordinators”. The inclusion of Transmission Planners and Planning Coordinators is appropriate because these entities will generally have the best planning horizon information and expertise to review the CAP.

Response: Thank you for your comment.

The drafting team asserts that the Reliability Coordinator is responsible for maintaining the operating reliability of the Bulk Electric System within its Reliability Coordinator Area. When a deficiency is identified, the Reliability Coordinator should make the decision whether or not to allow the RAS to remain in-service until the Corrective Action Plan is completed. As the drafting team has noted in responses to other comments, the RC has the “flexibility” to request information or assistance from relevant entities (third parties) to participate in the reviews if they believe it will enhance the quality and efficiency of the review process. This flexibility allows the RC to garner input from any impacted Transmission Planners and Planning Coordinators.

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment: There appears to be a gap between R6 and R7, from the point where each RAS owner submits a CAP to its RC, and then implementing the CAP. There should be a requirement placed upon the RC where a review of the CAP is completed and feedback provided to the RAS owner.

Response: Thank you for your comment.

The drafting team asserts that the Reliability Coordinator is responsible for maintaining the operating reliability of the Bulk Electric System within its Reliability Coordinator Area. When a deficiency is identified and a CAP is created, unless the CAP can be completed the same day, the Reliability Coordinator will most likely impose operating restrictions to ensure reliability until the RAS deficiency is resolved. The drafting team contends the RAS-entity will work closely with the RC to expedite the return to service date of the RAS. The drafting team asserts because the RC and RAS-entity have a mutual interest in returning the RAS to service as soon as possible to promote the reliability of the BES, their motivation and collaboration on this effort is sufficient, and does not necessitate the need for an additional requirement in the standard.

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3

Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Selected Answer: No

Answer Comment: The requirement R7 is very ambiguous about the time-frame for implementing a corrective action plan. Who approves the proposed schedule?

Response: Thank you for your comments.

Each CAP is unique and consequently the implementation and completion of each CAP will be unique as well. The RAS-entity submits the CAP to the reviewing RC. Although RC "approval" isn't mandated in a requirement, the RAS-entity must update the CAP if actions or timetables change, and communicate with the RC throughout CAP implementation and completion.

The drafting team asserts that the Reliability Coordinator is responsible for maintaining the operating reliability of the Bulk Electric System within its Reliability Coordinator Area. When a deficiency is identified and a CAP is created, unless the CAP can be completed the same day, the Reliability Coordinator will most likely impose operating restrictions to ensure reliability until the RAS deficiency is resolved. The drafting team contends the RAS-entity will work closely with the RC to expedite the return to service date of the RAS. The drafting team asserts because the RC and RAS-entity have a mutual interest in returning the RAS to service as soon as possible to promote the reliability of the BES, their motivation and collaboration on this effort is sufficient, and does not necessitate the need for an additional requirement in the standard.

Chris Scanlon - Exelon - 1 -

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Selected Answer: Yes

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: No

Answer Comment: R6 and R7 should specify a CAP is created only if deficiency is on the RAS-owners part of the RAS. As written, all RAS-owners would be responsible for submitting CAPs if a single deficiency was identified on just one part of the RAS. As written, a RAS-owner would be responsible for writing a CAP and implementing the CAP for something they may have no control over, if the deficiency is on another RAS-owners part of the RAS.

Response: Thank you for your comments.

If there are no deficiencies found, then it is not necessary to develop a CAP. The definition of a Corrective Action Plan (CAP) in the Glossary of Terms Used in NERC Reliability Standards is: A list of actions and an associated timetable for implementation to remedy a specific problem. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities.

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: Yes

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment: Although the Corrective Action Plan (CAP) does address the reliability objectives it is unclear on the responsibilities of the parties involved. As the requirement is written, the Owner must submit the corrective action plan. There is a little confusion on any RAS that have multiple owners. Would ALL the owners need to submit a CAP or only the owner of the equipment in question? SRP recomends clarifying and possibly designating operator as the one to submit the CAP.

Response: Thank you for your comments.

If there are no deficiencies found, then it is not necessary to develop a CAP. The definition of a Corrective Action Plan (CAP) in the Glossary of Terms Used in NERC Reliability Standards is: A list of actions and an associated timetable for implementation to remedy a specific problem. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities.

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment: Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Response: Please see the drafting team's responses to the referenced comments.

David Greene - SERC - 1,10 - SERC

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Selected Answer: Yes

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer: Yes

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment: ATC recommends revising R6 to explicitly include the Planning Coordinator with working like, ". . . submit the CAP to its reviewing Reliability Coordinator and any applicable Planning Coordinators". The inclusion of Planning Coordinators is appropriate because Planning Coordinators will generally have the best information and expertise to review the CAP.

Response: Thank you for your comment.

The drafting team asserts that the Reliability Coordinator is responsible for maintaining the operating reliability of the Bulk Electric System within its Reliability Coordinator Area. When a deficiency is identified, the Reliability Coordinator should make the decision whether or not to allow the RAS to remain in-service until the Corrective Action Plan is completed. As the drafting team has noted in responses to other comments, the RC has the "flexibility" to request information or assistance from relevant entities (third parties) to participate in the reviews if they believe it will enhance the quality and efficiency of the review process. This flexibility allows the RC to garner input from any impacted Transmission Planners and Planning Coordinators.

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer:	No
Answer Comment:	Requirement R6 reads as follows: "Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)." As written, R6 doesn't clearly assign the responsibility to the RAS-owner and only states they shall participate. Standard requirements need to be specific on who is responsible for what, and when. We also suggest that any CAP being submitted to the PC (we feel that the PC is appropriate as discussed in comments on R1) be a "mutually agreed upon" CAP. To address this issue we suggest the following: Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall develop a mutually agreed upon

Corrective Action Plan (CAP) with all affected Reliability Coordinators and submit the CAP to its reviewing Planning Coordinator(s).

We suggest that the full responsibility of the development of the CAP rest with the RAS-entity. The rationale box states this but it needs to be clear in the requirement. Irrespective of complexity, the need to collaborate with others and hire consulting services, the responsibility should rest solely on the RAS-owner.

Also there may be a need for an additional requirement to notify the PC and TOP when the CAP has been completed, and the RAS is performing correctly. We will leave this for consideration by the SDT and believe this brings specific closure to any RAS deficiency.

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities. The drafting team declines to make the suggested change.

Standard utility practice as well as other NERC Reliability Standards ensure the TOP and PC will be aware of the CAP completion.

NERC

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: No

Answer Comment: As mentioned in our previous comments, Peak recognizes that the RC or TOP may impose operating restrictions to ensure reliability until the RAS deficiency is resolved but maintains that the CAP should be reviewed by an independent party to assure that it addresses the reliability issues in a reasonable timeframe. . For example, a CAP could be created with an unreasonable timeframe that unnecessarily extends a reliability issue. This independent review by the RC and subsequent required action by the RAS-entity exists for new RAS but not for CAPs, which appears inconsistent with the intent of the Standard. A process similar to that described in R2 and R3 should also apply to CAPs and not just new and functionally modified RAS.

Response: Thank you for your comment.

The drafting team asserts that the Reliability Coordinator is responsible for maintaining the operating reliability of the Bulk Electric System within its Reliability Coordinator Area. When a deficiency is identified, the Reliability Coordinator should make the decision whether or not to allow the RAS to remain in-service until the Corrective Action Plan is completed. As the drafting team has noted in responses to other comments, the RC has the “flexibility” to request information or assistance from relevant entities (third parties) to participate in the reviews if they believe it will enhance the quality and efficiency of the review process. This flexibility allows the RC to garner input from any impacted Transmission Planners and/or Planning Coordinators.

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Selected Answer: No

Answer Comment: We suggest the following rewording:

"Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall develope a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)."

R6 should reflect that it is either solely the RAS owner's responsibility **or** both the RC and RAS owner must have responsibility and "participate" in developing the CAP together. If the CAP requires mutual participation to develop, then both parties (the RAS owner AND the RC) must have compliance responsibility.

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities. The drafting team declines to make the suggested change.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Selected Answer: Yes

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: No

Answer Comment: Reclamation suggests that the RAS-entity should be responsible for the Corrective Action Plans (CAPs) called for in requirements R6 and R7. Each RAS-owner should not be responsible for developing CAPs and coordinating them with the Reliability Coordinator (RC) because this could result in duplication of efforts or inconsistent corrective actions. As outlined in the Technical Justifications, "[t]he purpose of the RAS-entity is to be the single information conduit with each reviewing Reliability Coordinator (RC) for all RAS-owners for each RAS." When there are several owners involved in a RAS, the RC should communicate with the RAS-entity as one point of contact to ensure that an overall CAP addresses any RAS deficiencies.

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities. The drafting team declines to make the suggested change.

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2

Ali Miremadi	CAISO	WECC	2

Selected Answer: No

Answer Comment: The SRC agrees that the RAS entity should develop Corrective Action Plans to evaluate RASs to address issues and/or deficiencies identified by their evaluations, but would suggest that such entities be required to provide the Corrective Action Plans to their Reliability Coordinator ***and Planning Coordinator*** for review.

Response: Thank you for your comment.

The drafting team asserts that the Reliability Coordinator is responsible for maintaining the operating reliability of the Bulk Electric System within its Reliability Coordinator Area. When a deficiency is identified, the Reliability Coordinator should make the decision whether or not to allow the RAS to remain in-service until the Corrective Action Plan is completed. As the drafting team has noted in responses to other comments, the RC has the “flexibility” to request information or assistance from relevant entities (third parties) to participate in the reviews if they believe it will enhance the quality and efficiency of the review process. This flexibility allows the RC to garner input from any impacted Transmission Planners and Planning Coordinators. The drafting team declines to make the suggested change.

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment: See comment in no. 7.

Response: Please see the drafting team's responses to the referenced comment.

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment: "Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)."

As written, R6 doesn't clearly assign the responsibility to the RAS-owner and only states they shall participate. Standard requirements need to be specific on who is responsible for what, and when. We also suggest that any CAP being submitted to the RC be a "mutually agreed upon" CAP. To address this issue we suggest the following:

Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall develop a mutually agreed upon Corrective Action Plan (CAP) with all affected Reliability Coordinators and submit the CAP to its reviewing

Reliability Coordinator(s).

We suggest that the full responsibility of the development of the CAP rest with the RAS-owner. The rationale box states this but it needs to be clear in the requirement. Irrespective of complexity, the need to collaborate with others and hire consulting services, the responsibility should rest solely on the RAS-owner.

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities. The drafting team declines to make the suggested change.

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments

Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: Yes

Answer Comment:

Attachment 1, Section III-Implementation states, "5. Documentation describing the functional testing process." Dominion recommends deleting this bullet. This information is not necessarily available during the preliminary design phase. The approval of the design is sought prior to detailed engineering. (Planning)

In R5 it states that the RAS owner analyzes the event, but in flow chart it states RAS owner and TP. Dominion suggests that the content in the Flow Chart be consistent with language of the Requirement.

R5 references the timeframe "within 120 calendar days", however in other areas of the document the time frame is stated to be "within XX calendar months". Dominion suggests updating the document to reflect the actual timeframe. Dominion also believes clarification is needed to establish "full calendar months" versus "months".

Response: Thank you for your comments.

The drafting team maintains that sufficient information must be provided to the RC to allow a proper review including information describing the RAS-entity's plan for periodic testing. The drafting team declines to make the suggested change.

The drafting team made the change to the flowchart.

The drafting team modeled the requirement after the requirements of PRC-004. The drafting team maintains that the time increment of 'days' rather than 'months' is preferable for this requirement and declines to make the suggested change.

The drafting team uses the clarifier 'full' to be clear that partial time increments are not counted. For example, for four calendar months, if the starting point is in the middle of a calendar month (October 15), four full calendar months would begin November 1 and continue through February 28 (the last day of the month of the stated period).

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Selected Answer: No

Answer Comment: See the comments in #2, which is critical to R6. Furthermore, the team should modify the R6 phrase as shown below:

"…each RAS-owner shall participate in developing a Corrective Action Plan with the RAS-entity which shall and submit the CAP to its reviewing Reliability Coordinator…."

This will result in one RAS-entity submitted CAP to the reviewing RC.

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities. The drafting team declines to make the suggested change.

Likes: 4

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1

Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Selected Answer: No

Answer Comment:	Requirement R6 reads as follows: “Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s).” As written, R6 doesn’t clearly assign the responsibility to the RAS-owner and only states they shall participate. Standard requirements need to be specific on who is responsible for what, and when. We also suggest that any CAP being submitted to the RC be a “mutually agreed upon” CAP. To address this issue we suggest the following: Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner and affected Reliability Coordinator(s) shall develop a mutually agreed upon Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s). Also, there may be a need for an additional requirement to notify the RC and TOP when the CAP has been completed, and the RAS is performing correctly. This should be considered by the SDT. This brings specific closure to any RAS deficiency. Requirement R5 stipulates that the RAS-owner identifies deficiencies to its reviewing RC. Suggest R6 be revised to read: “Within six-full-calendar months of identifying or of being notified of a…”

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities. The drafting team declines to make the suggested change.

The drafting team revised Requirement R7 to include the notification of each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

The drafting team revised Requirement R6.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Answer Comment: ERCOT supports the comments submitted by the ISO/RTO Council.

Response: Please see the drafting team's responses to the referenced comments.

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: Yes

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: Yes

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer: No

Answer Comment: TANC has concerns with the current language in R5, R6, and R7, because it appears these requirements would assign the same or similar responsibilities to "each RAS-owner" when a single RAS operates or fails to operate as expected. In circumstances where a single RAS has multiple RAS-owners, the current language would potentially create overlapping responsibilities to analyze the RAS performance and develop/implement a Corrective Action Plan. It seems that these responsibilities established in R5, R6, and R7 would be more appropriately assigned to the single RAS-entity for a RAS rather than to each RAS-owner.

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Requirements R5 and R6 do require each RAS-entity to perform the actions associated with the requirements. The drafting team maintains this will promote reliability and that entities will not duplicate efforts. Each entity is responsible only for its RAS components. The drafting team is confident that entities will communicate with each other if there is any question or doubt of responsibility. The drafting team declines to make the suggested change.

The drafting team revised Requirement R7 to include the notification of each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

The drafting team revised Requirement R6.

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:	Requirement R6 reads as follows: "Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)." As written, R6 doesn't clearly assign the responsibility to the RAS-owner and only states they shall participate. Standard requirements need to be specific on who is responsible for what, and when. We also suggest that any CAP being submitted to the RC be a "mutually agreed upon" CAP. To address this issue we suggest the following: Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall develop a mutually agreed upon Corrective Action Plan (CAP) with all affected Reliability Coordinators and submit the CAP to its reviewing Reliability Coordinator(s). We suggest that the full responsibility of the development of the CAP rest with the RAS-owner. The rationale box states this but it needs to

be clear in the requirement. Irrespective of complexity, the need to collaborate with others and hire consulting services, the responsibility should rest solely on the RAS-owner.

Requirement R6 states, “Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5…”, however, a notification does not come out of R5 since the applicability to both R5 and R6 is with the RAS owner.

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities. The drafting team declines to make the suggested change.

The drafting team revised Requirement R6.

Richard Vine - California ISO - 2 -

Selected Answer: No

Answer Comment: The California ISO supports the comments of the ISO/RTO Standards Review Committee

Response: Please see the drafting team's responses to the referenced comments.

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Andrew Gallo - Austin Energy - 6 -

Selected Answer: Yes

Dixie Wells - Lower Colorado River Authority - 5 -

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments

Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Selected Answer: Yes

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Selected Answer: Yes

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:	Yes
Don Schmit - Nebraska Public Power District - 5 -	
Selected Answer:	Yes
Jeff Wells - Grand River Dam Authority - 3 -	
Selected Answer:	Yes
Rachel Coyne - Texas Reliability Entity, Inc. - 10 -	
Selected Answer:	No
Answer Comment:	Texas RE is concerned there could be an extended time frame where a RAS with a known deficiency will be in service since the requirement to develop a Corrective Action Plan (CAP) is do so within six months. Texas

RE is also concerned there is no defined time frame for implementing the CAP.

Response: Thank you for your comments.

The drafting team disagrees that there is a reliability risk during the time interval associated with the CAP development though completion of the CAP because the Reliability Coordinator will require the RAS-entity to modify operating procedures, System configuration, generation dispatch, or employ other methods to alleviate the deficient RAS. The RAS review associated with new or functionally modified RAS is a more comprehensive review that entail the design, operations, and testing of the RAS.

The definition of a Corrective Action Plan (CAP) in the Glossary of Terms Used in NERC Reliability Standards is: A list of actions and an associated timetable for implementation to remedy a specific problem. Each CAP is unique and consequently the implementation and completion of each CAP will be unique as well. The RAS-entity submits the CAP to the reviewing RC. Although RC "approval" isn't mandated in a requirement, the RAS-entity must update the CAP if actions or timetables change, and communicate with the RC throughout CAP implementation and completion.

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Selected Answer:	No
Answer Comment:	The RC needs to be given the authority to reject the CAP, or suggest changes to the CAP.

Response: Thank you for your comment.

The RAS-entity must submit the CAP and other Attachment 1 information to the RC if functional modifications to the RAS are proposed. Accordingly, pursuant to Requirement R3, the RAS-entity must obtain approval of the RAS from each reviewing Reliability Coordinator.

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:	No
Answer Comment:	Hydro One Networks Inc. believes that as quoted below, R6 does not clearly assign the responsibility to the RAS-owner and only states that they "shall participate". "Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)." Standard requirements need to be specific on as to who is responsible for what, and when. We also suggest that any CAP being submitted to the RC be a "mutually agreed upon" CAP. To address these issues, we suggest revising the wording to read the following: "Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirements R4 and R5 state that each RAS-owner shall develop with all affected RCs, a mutually agreed upon Corrective

Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)". However, Hydro One Networks Inc. suggests that the full responsibility of the development of the CAP rest with the RAS-owner. The rationale box states that the full responsibility of the development of the CAP rests with the RAS-owner, but this needs to be clear, and explicitly stated in the requirement as well. Irrespective of complexity, the need to collaborate with others, hire consulting services, etc., the responsibility should rest solely on the RAS-owner.

Requirement R6 states, "Within six-full-calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5…", however, Hydro One would like to point out that a notification does not result from requirement R5 since the applicability to both R5 and R6 is with the RAS owner themselves.

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities. The drafting team declines to make the suggested change.

The drafting team revised Requirement R6.

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer: No

Answer Comment: The RAS-entity should be included in Requirements R6 and R7 in a coordinating role between the RAS-owners and the TP and/or RC. It should be made clear that the RAS-owners are only responsible for their portion of the RAS.

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. The drafting team wrote Requirement R6 such that each RAS-entity shall participate in developing a CAP. This collaboration will promote awareness of RAS degradation and the efforts and timetables to return the RAS to service. Measure M6 states that acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each RAS-entity and each reviewing Reliability Coordinator. Therefore, if a RAS-entity does not own the RAS component that is deficient, it can show evidence of participation through emails with the other RAS-entities.

Requirement R7 mandates each RAS-entity to implement its portion of the RAS.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments

Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Selected Answer: No

Answer Comment: We disagree with the SDT that there needs to be two requirements to cover CAPs. These requirements should be consolidated and simplified to avoid unnecessary confusion and potential compliance impacts. Furthermore, CAPs are administrative in nature and we recommend removing these requirements under Paragraph 81 Administrative criteria.

Response: Thank you for your comments.

The drafting team maintains there are separate and distinct reliability objectives associated with the two requirements that reference CAPs and declines to combine them.

The drafting team disagrees that CAPs are administrative in nature, no changes made.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

6. Implementation Plan: Do you agree with the Implementation Plan? If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6

Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: Yes

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Chris Scanlon - Exelon - 1 -

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Selected Answer: Yes

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC **Selected Answer:** Yes
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP **Selected Answer:** Yes
Molly Devine - IDACORP - Idaho Power Company - 1 - **Selected Answer:** Yes
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC **Selected Answer:** No

Answer Comment: SRP notices possible confusion on the implementation for R4 and R8. The rationale for R4 and R8 state that the 60 month time period begins on the effective date of the standard. However, the implementation plan does not state that similarly. There is potential confusion for this as many entities are likely to attempt to have their evaluations and functional tests completed by the effective date.

Response: Thank you for your comment.

The 60 full calendar month interval in Requirement R4 and the six calendar year interval in Requirement R8 both begin on the effective date of PRC-012-2. The initial performance of those requirements must be completed within the specified interval after the effective date of PRC-012-2. The drafting team added language to the Implementation Plan to provide additional clarity.

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment: Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Response: Please see the drafting team's responses to the referenced comments.

David Greene - SERC - 1,10 - SERC

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Selected Answer: Yes

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer: Yes

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: Yes

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment: Peak interprets the Implementation Plan as grandfathering in all existing RAS, which means review and approval of existing RAS is not required – only for new or modified RAS. The revised Standard does not address existing RAS, and therefore neglects any potential reliability issues associated with them. Peak seeks clarity on this issue.

Response: Thank you for your comment.

The standard addresses all RAS. Requirements R1, R2, and R3 address new or functionally modified RAS. Requirements R4, R5, and R8 pertain to all RAS. Existing RAS are not grandfathered; however, they would not need to go through the new RAS-review process (Requirements R1, R2, and R3) until such time that a functional modification was required due to an issue identified via Requirements R4, R5, or R8. The functional modification would be described and submitted to the reviewers via a Corrective Action Plan (CAP) in conjunction with Requirement R6.

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Selected Answer: Yes

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segment
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Selected Answer: Yes

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment: See comment in no. 7.

Response: Please see the drafting team's responses to the referenced comment.

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment: The Implementation Plan should be modified to include clarification for implementation of R4. TFSP suggests adding the language used in the Rationale box for R4, which says: "Sixty-full-calendar months, which begins on the effective date of the standard pursuant to the implementation plan…"

The standard or the Implementation Plan should allow the RAS-owner sufficient time to mitigate a design deficiency identified as part of R4, such as the lack of redundancy without removing the RAS from service. Clarification should be provided to allow for continued operation of an existing RAS after a single component failure scenario is identified until a Corrective Action Plan can be completed.

Response: Thank you for your comments.

The 60 full calendar month interval in Requirement R4 begins on the effective date of PRC-012-2. The initial performance of the requirement must be completed within the specified interval after the effective date of PRC-012-2. The drafting team added language to the Implementation Plan to provide additional clarity.

The drafting team asserts that the Reliability Coordinator is responsible for maintaining the operating reliability of the Bulk Electric System within its Reliability Coordinator Area. If a design deficiency is identified as part of the Requirement R4 planning evaluation, the Planning Coordinator in conjunction with the Reliability Coordinator should make the decision whether or not to allow the RAS to remain in-service until the Corrective Action Plan is completed.

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Selected Answer: Yes

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Selected Answer: No

Answer Comment: The effective date in Implementation Plan should be increased from 12 month to 36 months after the first day of the first calendar quarter after the date the standard is approved. This reason for this delay is that standard establishes a new working framework between RAS-owners, RAS-entities, TPs, and RCs. That itself will involve considerable start-up effort. In return for this added delay, the first periodic review of each

RAS under R4 could be due within 36 months, with subsequent reviews every 60 months.

Response: Thank you for your comment.

The drafting team lengthened the implementation period of the standard to thirty-six months to provide entities adequate time to establish the new working frameworks.

Likes: 4

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3

Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10

Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1

Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Selected Answer: No

Answer Comment:

The Implementation Plan should be modified to include clarification for implementation of R4. Suggest adding the language used in the Rationale for Requirement R4, which says: "Sixty-full-calendar months, which begins on the effective date of the standard pursuant to the implementation plan…"

The standard or the Implementation Plan should allow the RAS-owner sufficient time to mitigate a design deficiency identified as part of R4, such as the lack of redundancy without removing the RAS from service. Clarification should be provided to allow for continued operation of an existing RAS after a single component failure scenario is identified until a Corrective Action Plan can be completed.

The Implementation Plan should address the possible scenario of a RAS misoperation occurring within 120 days of the Standard's effective date, and if R5 would apply. Would this misoperation require the development of a CAP after the effective date of the Standard? This would apply for R6 and R7 as well.

For testing records will the RAS-owner need to have documentation of testing prior to the standard's effective date? This should be clarified in the Implementation Plan.

Response: Thank you for your comments.

The 60-full calendar month interval in Requirement R4 begins on the effective date of PRC-012-2. The initial performance of the requirement must be completed within the specified interval after the effective date of PRC-012-2. The drafting team added language to the Implementation Plan, rationale box, and Supplemental Material section of the standard to provide additional clarity.

The drafting team asserts that the Reliability Coordinator is responsible for maintaining the operating reliability of the Bulk Electric System within its Reliability Coordinator Area. If a design deficiency is identified as part of the Requirement R4 planning evaluation, the Planning Coordinator in conjunction with the Reliability should make the decision whether or not to allow the RAS to remain in-service until the Corrective Action Plan is completed.

Requirement R4 states that the entity shall analyze the RAS performance and provide the results of the analysis, including any identified deficiencies, to its reviewing Reliability Coordinator(s) within 120 calendar days of a RAS operation or failure of a RAS to operate when expected; therefore, the effective date of the standard is irrelevant. Yes, Requirements R6 and R7 mandate a Corrective Action Plan be developed, submitted, and implemented.

The functional testing of a RAS is a new requirement; consequently, no records of functional testing prior to the effective date of the standard are required.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Answer Comment: N/A

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: No

Answer Comment: In the Implementation Plan, page 2, the following sentence has a grammatical/mechanical issue: “As of the date of posting of this Implementation Plan, however, the Commission has not issued an Final Order approving and retirement the Reliability Standards enumerated above.”

Response: Thank you for your comment.

The drafting team revised the language to reflect the issuance of FERC Order 818 approving the proposed standards and definition of “Remedial Action Scheme.”

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer: Yes

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment: The Implementation Plan should allow the RAS-owner sufficient time to mitigate a design deficiency identified as part of R4, such as the lack of redundancy without removing the RAS from service. Clarification should be provided to allow for continued operation of those RAS, that are already in service when the standard becomes effective, after a single component failure scenario is identified until a Corrective Action Plan can be completed.

Response: Thank you for your comment.

The drafting team asserts that the Reliability Coordinator is responsible for maintaining the operating reliability of the Bulk Electric System within its Reliability Coordinator Area. If a design deficiency is identified as part of the Requirement R4 planning evaluation, the Planning Coordinator in conjunction with the Reliability Coordinator should make the decision whether or not to allow the RAS to remain in-service until the Corrective Action Plan is completed.

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Andrew Gallo - Austin Energy - 6 -

Selected Answer: Yes

Dixie Wells - Lower Colorado River Authority - 5 -

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Selected Answer: Yes

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Selected Answer: Yes

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Don Schmit - Nebraska Public Power District - 5 -	
Selected Answer:	Yes
Jeff Wells - Grand River Dam Authority - 3 -	
Selected Answer:	Yes
Rachel Coyne - Texas Reliability Entity, Inc. - 10 -	
Selected Answer:	Yes
Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3	
Selected Answer:	Yes

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment: The Implementation Plan should be modified to include clarification for implementation of R4. Hydro One Networks Inc. agrees with the NPCC's TFSP in adding the language used in the Rationale box for R4, which says: "Sixty-full-calendar months, which begins on the effective date of the standard pursuant to the implementation plan…"

The standard or the Implementation Plan should allow the RAS-owner sufficient time to mitigate a design deficiency identified as part of R4, such as the lack of redundancy without removing the RAS from service. Clarification should be provided to allow for continued operation of an existing RAS after a single component failure scenario is identified until a Corrective Action Plan can be completed.

Response: Thank you for your comments.

The 60 full calendar month interval in Requirement R4 begins on the effective date of PRC-012-2. The initial performance of the requirement must be completed within the specified interval after the effective date of PRC-012-2. The drafting team added language to the Implementation Plan, rationale box, and Supplemental Material section of the standard to provide additional clarity.

The drafting team asserts that the Reliability Coordinator is responsible for maintaining the operating reliability of the Bulk Electric System within its Reliability Coordinator Area. If a design deficiency is identified as part of the Requirement R4 planning evaluation, the Planning Coordinator in conjunction with the Reliability Coordinator should make the decision whether or not to allow the RAS to remain in-service until the Corrective Action Plan is completed.

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer: Yes

Answer Comment: The Implementation Plan should specify when the first 5 year evaluation required by R4 should be completed for an existing RAS.

Response: Thank you for your comment.

The 60 full calendar month interval in Requirement R4 begins on the effective date of PRC-012-2. The initial performance of the requirement must be completed within the specified interval after the effective date of PRC-012-2. The drafting team added language to the Implementation Plan, rationale box, and Supplemental Material section of the standard to provide additional clarity.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1

Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Selected Answer: No

Answer Comment: We ask the SDT to clarify whether the approval process and the first technical evaluation needs to be performed before or after the effective date of the standard.

Response: Thank you for your comment.

The approval process associated with the RAS review can only take place after the effective date of the standard. The 60 full calendar month interval in Requirement R4 begins on the effective date of PRC-012-2. The initial performance of the requirement must be completed within the specified interval after the effective date of PRC-012-2. The drafting team added language to the Implementation Plan, rationale box, and Supplemental Material section of the standard to provide additional clarity.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

7. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Answer Comment: We suggest that the standard have applicability to only the RAS entity, normally the primary Transmission Owner for the region affected. Including more than one party will make this standard too cumbersome and difficult to manage. The primary application of a RAS is to multi-facility, wide-area disturbances and as such is best vested in the Transmission Owner, who has a wider "system" viewpoint than the Generator Owner. We are concerned that Generator Owners may become inadvertent RAS-owners simply by owning a small fraction of the equipment needed for the RAS, and thus become subject to requirements R5 through R8, when they are typically passive parties to the RAS.

Response: Thank you for your comment.

The drafting team maintains that RAS-ownership should be according to component ownership. The RAS-entity owns the components that make up a RAS, and as the asset owner, is responsible for the purchase, design, operation, maintenance, and testing of a RAS. This includes protection system components as well as non-protection system components. Otherwise, components may be left out of functional testing (R8), from single component failure and malfunction evaluations (R4.1.3 and R4.1.4), and from operational analysis (R5) leading to reliability gaps.

Based on comments, the drafting team revised the standard such that Requirements R5 and R6 apply to the RAS-entity. The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. As explained in the Technical Justification, each separate RAS-entity is obligated to participate in various activities, as identified by the Requirements to the extent of their ownership. It is not the intent of the drafting team, however, to specify how multiple RAS-entities must coordinate.

John Fontenot - Bryan Texas Utilities - 1 -

Answer Comment: na

Emily Rousseau - MRO - 1,2,3,4,5,6 – MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5

Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Answer Comment: For R5, we propose revised wording that "within 120 days, or on a mutually agree upon schedule." This would allow earlier or later completion of the analysis when warranted by unusual circumstances.

Response: Thank you for your comment.

The drafting team made the suggested change.

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Answer Comment:	With regards to R5: What is the benefit of providing the reviewing RC with results of a successful RAS operation? With regards to R8: Although functional testing would verify that the scheme is working as designed, there is no reason to believe that an RAS is any different from another protection system i.e., it would need to be tested at intervals outside the normal maintenance program. The testing of RAS should fall in line with PRC-005-3 requirements for monitored systems and unmonitored systems. By requiring "at least once every six calendar years, each RAS-owner shall perform a functional test," the drafting team is forcing all owners of a RAS that has any Protection Systems in it to abandon the PRC-005-3 12 year Maximum Maintenance Intervals allowed in tables 1-1, 1-2, 1-3, 1-5, and 4. If Requirement R9 is adopted as stated in this draft of the standard, each segment of a RAS would have to be tested at a maximum interval of 6 calendar years. This would require, for example, that voltage and current sensing devices providing inputs to protective relays of a RAS

“shall” be tested “at least once every six calendar years” instead of 12 Calendar years allowed in Table 1-3 of PRC-005-3.

Response: Thank you for your comments.

The drafting team revised the standard to state that Requirement R5 only requires a RAS-entity to provide the results of RAS operational performance analysis if deficiencies were identified. Please see the revised requirements and complementary revisions to the measures, rationale boxes, supplemental materials, and Attachments.

The drafting team revised the standard to allow RAS that have limited impact to have functional testing intervals of up to twelve full calendar years. However, the drafting team contends that the six full calendar year interval is appropriate for the higher impact RAS given the potential negative impact to BES reliability should a RAS operate incorrectly. Existing regional practices include more frequent RAS functional testing than the proposed six full year calendar interval. Requirement 8 in PRC-012-2 is only applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers (PLCs), personal computers (PCs), multi-function programmable relays, remote terminal units (RTUs), and logic processors that have no applicability within PRC-005.

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 – WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1

Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Answer Comment:

1. We ask for a clarification on the PRC-012-2 definition of RAS Owner to only "exclusively" include the owner of the scheme, and not include a "participating" entity in the RAS operation. The participating entity equipment would be covered by other standards such PRC-005-2 and thus should be excluded from standard.

2. The requirement R8 will require that the RAS is tested every 6 years, which is equivalent to any unmonitored relays that we have under PRC-005. However, testing the RAS may prove to be more laborious since it will most likely require coordination among multiple participating entities, so a more relaxed test sequence (12 years) would be preferred.

Response: Thank you for your comments.

Because of confusion between the terms, the drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If the individual owners of a RAS decide that it would be advantageous for one RAS-entity to represent all of the other owners and assume a lead role in performing some of the required tasks, the standard does not prohibit this type of arrangement. Nevertheless, each RAS-entity must still be able to demonstrate compliance with the individual requirements the standard.

The drafting team revised the standard to allow RAS that have limited impact to have functional testing intervals of up to twelve full calendar years. However, the drafting team contends that the six full calendar year interval is appropriate for the higher impact RAS given the potential negative impact to BES reliability. Existing regional practices include more frequent RAS functional testing than the proposed six full calendar year interval.

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Answer Comment:

RAS-entity should be responsible for R5 instead of RAS-owner. The RAS-entity, being designated to represent all RAS-owners, is in the best position to evaluate the operation of a RAS.

RAS-entity should be responsible for R8 functional testing.

R9 should include a sub-requirement for RCs to share their database with neighboring RCs to provide coordination of RAS schemes near RC borders.

Response: Thank you for your comments.

Because of confusion between the terms, the drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If the individual owners of a RAS decide that it would be advantageous for one RAS-entity to represent all of the other owners and assume a lead role in performing some of the required tasks, the standard does not prohibit this type of arrangement. Nevertheless, each RAS-entity must still be able to demonstrate compliance with the individual requirements the standard.

The drafting team asserts that there is not a need for a requirement in PRC-012 for an RC to share its RAS database because information sharing among neighboring RCs is already covered in other NERC Reliability Standards.

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Answer Comment:

There are numerous references to components of a RAS scheme in the standard and supplemental material, but there is no clear definition of what constitutes a component of a RAS scheme. A lack of a clear definition can lead to different interpretations of what a RAS component is. For example, Requirement R4.3 requires that "the possible inadvertent operation of the RAS resulting from any single RAS component malfunctions satisfies all of the following" conditions in 4.3.1 thru 4.3.5. While it is implied that the RAS components could include elements such as the RAS controller, communications, control circuitry, supervisory relays or functions (breaker 52A contact), and/or voltage or current sensing devices, it is not clearly stated. This leaves it open for some entities to possibly consider additional items such as a circuit breaker as a RAS component and other entities to not consider it. It could also allow some entities to take a more relaxed approach and exclude components that should possibly be included. A definition or explanation of RAS components should be added to the standard similar to the definitions used in PRC-005-4 (i.e. Automatic Reclosing and Sudden Pressure Relaying).

Response: Thank you for your comments.

The drafting team maintains that the team should not attempt to develop an exhaustive list of RAS components. An exhaustive list of components is not practical given the variety that could be applied in RAS design and implementation. See Item 4a in the Implementation Section of Attachment 1 in the Supplemental Material section for typical RAS components for which redundancy may be considered. The RAS-entity should have a clear understanding of what components were applied to put a RAS into service and which were already present in the system before a RAS was installed. The RC will make the final determination regarding which components should be regarded as RAS components during its review.

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Answer Comment:	Currently as the standard is written, R5 and R6 require each RAS-owner to submit the results of the analysis and a CAP if needed. Tri-State does not believe it should be required that each RAS-owner submit the results and/or CAP rather than the RAS-entity. The RAS-entity can collect the results and submit 1 report/CAP, instead of several individual submittals from the seperate RAS-owners. Also, Tri-State believes there is a numbering issue in Section II of Attachment 1 of the standard. It looks like "Documentation showing that the possible inadvertent operation of the RAS resulting from any singles RAS component malfunction satisfies all of the following:" should be #5 since it is a separate topic from #4.

Response: Thank you for your comments.

Based on comments, the drafting team revised the standard such that R5 and R6 requirements apply to the RAS-entity. The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. As explained in the Technical Justification, each separate RAS-entity is obligated to participate in various activities, as identified by the Requirements to the extent of their ownership. It is not the intent of the drafting team, however, to specify how multiple RAS-entities will coordinate.

The drafting team made the edit.

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer Comment:

a. The Rationale Box for R6 states that the "RAS-owner" will need to submit information in Attachment 1 to the RC, should this be the RAS-entity?

b. In R6, if the RAS-owner is the entity that performed the analysis in R4 of R5, when does the 6 month clock start (i.e., when was it notified)?

c. For R7, is the intent that each RAS-owner update the CAP with the RC? It seems like this should be the job of the RAS-entity, not multiple RAS-owners.

Response: Thank you for your comments.

Because of confusion between the terms, the drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If the individual owners of a RAS decide that it would be advantageous for one RAS-entity to represent all of the other owners and assume a lead role in performing some of the required tasks, the standard does not prohibit this type of arrangement. Nevertheless, each RAS-entity must still be able to demonstrate compliance with the individual requirements the standard.

The drafting team revised Requirement R6 for clarification.

Yes, each RAS-entity must implement the CAP as it relates to its facilities. The drafting team disagrees that only one entity needs to be responsible.

Joshua Andersen - Salt River Project - 1,3,5,6 – WECC

Answer Comment:

As written the rationale for R8 is not incorporated into the requirement. R8 rationale states that correct operation of a RAS segment would qualify as a functional test. Please state that in the requirement so there is no confusion or debate if a correct operation resets the time frame necessary to perform a test.

SRP recommend the removal of the word “Requirement” in front of any R# designation. R1 stands for Requirement 1 and is sufficient. Saying "Requirement R1" is like saying Requirement Requirement 1. Also, the term “Requirement” is not a defined term.

Response: Thank you for your comments.

The drafting team added language to the measure for Requirement 8 indicating that a correct operation of a RAS segment would qualify as a functional test and the time frame for the segment that operated correctly would be reset. Segments that did not operate must be tested according to the planned testing schedule. In addition, the team will include that in the RSAW for PRC-012, Requirement R8.

The drafting team is adhering to the NERC style guide for Reliability Standards. Please address your comment to the appropriate NERC staff.

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer Comment: Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Response: Please see the drafting team's responses to the referenced comments.

David Greene - SERC - 1,10 - SERC

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1

David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Answer Comment: If a RAS has multiple owners, and one or more owners is not compliant to R8, does this mean that all owners, or the RAS-entity, are non-compliant?

Response: Thank you for your comments.

Because of confusion between the terms, the drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If the individual owners of a RAS decide that it would be advantageous for one RAS-entity to represent all of the other owners and assume a lead role in performing some of the required tasks, the standard does not prohibit this type of arrangement. Nevertheless, each RAS-entity must still be able to demonstrate compliance with the individual requirements of the standard.

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Answer Comment: IMEA questions the need to include DP in the applicability. It is likely a DP will only own a part of a RAS. It should be adequate to specify TO coordination to verify RAS performance.

In R8, IMEA recommends deletion of "...and the proper operation of non-Protection System components."; i.e., it should be adequate to indicate only "...verify overall RAS performance."

Response: Thank you for your comments.

The drafting team declines to make the suggested change removing the Distribution Provider (DP). Given the critical nature of RAS, every DP that owns all or part of a RAS must be held accountable to ensure BES reliability.

The focus of this requirement is verification of RAS functionality. Protection System components are addressed by PRC-005, but non-Protection System components such as programmable logic controllers are not applicable under PRC-005 so the drafting team is including them in PRC-012. The drafting team declines to make the suggested change.

Andrew Pusztai - American Transmission Company, LLC - 1 -

Answer Comment:

- For R5, ATC proposes revising wording that "within 120 days, or on a mutually agree upon schedule." This would allow earlier or later completion of the analysis when warranted by unusual circumstances.
- The purpose of Version 2 of PRC-005 was to consolidate all maintenance and testing of relays under one Standard. Having RAS testing within PRC-012-2 would be contrary to that end. ATC addresses this concern as follows:

Functional testing of RAS (as stated in Requirement 8 of PRC-012-2) is a maintenance and testing activity that would be better included in the PRC-005 standard. The present PRC-005-2 Reliability Standard is the maintenance standard that replaces PRC-005-1, 008, 011 and 017 and was designed to cover the maintenance of SPSs/RASs. However, Reliability Standard PRC-005-2 lacks intervals and activities related to non-protective devices such as programmable logic controllers. ATC recommends that a requirement for maintenance and testing of non-protective RAS components be added to a revision of PRC-005-2, rather than be an outlying maintenance requirement located in the PRC-012-2 Standard.

Response: Thank you for your comments.

The drafting team made the suggested change.

The functional testing of a RAS to verify its performance is different from the maintenance activities associated with the Protection System Components as detailed in the tables of PRC-005. Requirement 8 of PRC-012-2 is only applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers and are not Protection System Components and as such, do not belong in PRC-005. The Protection System definition used within PRC-005 ensures BES reliability through component testing to verify each component's ability to operate. Functional testing is not an activity in PRC-005. The drafting team chose functional testing to emphasize the logic and control functions of RAS. The drafting team contends that functional testing of the non-Protection System RAS components in PRC-012-2 complements the component testing of PRC-005.

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Answer Comment:

Regarding the rationale for Requirement R8--We agree with segmented testing. However, the requirement does not state this and implies an overall test should still be performed.

R8 currently states:

At least once every six-calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components.

Suggest revising to:

At least once every six-calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. This test can be either:

o An end to end test encompassing all components and testing actual functionality

o A segmented test to test all the components by grouping them together into blocks until all parts of the RAS have been tested

Additional information in the Technical Guideline may be required to explain how the six year cycle is measured when allowing segmented testing. Segmented testing can test all components of an RAS every six years, but an individual component could end up being tested once every 10 years. For example, a RAS is designed so that it is comprised of a segment "A", and a segment "B". Segment "A" is tested in year 1, segment "B" is tested in year 5. As per Requirement R8 the RAS has been tested within "six-calendar years." The clocks starts for the next functional test period, and segment "B" is tested in year 1 (one year since its first test), and segment "B" tested in year 5 (nine years since its first test). The RAS was tested within the “six-calendar years”, but segment “B” had a nine year interval. The requirement should be modified to state that all segments shall be tested in the same calendar year.

The RAS-owner should be included in Attachment 3.

Response: Thank you for your comments.

The requirement mandates the overall RAS performance be verified, not that an overall test be conducted. Furthermore, the rationale for Requirement R8 states: “Functional testing may be accomplished with end-to-end testing or a segmented approach.” The drafting team is not specifying the method, only the reliability objective. The drafting team declines to make the suggested change.

A more detailed description of the test intervals is now included in the Rationale and Supplementary Material. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment.

The consolidation of the terms RAS-entity and RAS-owner accomplish your suggestion.

Jared Shakespeare - Peak Reliability - 1 -

Answer Comment:

Peak was unable to locate the “consideration of comments” after the last round of comments posted on the NERC website. The “consideration of comments” are normally posted as part of the Standards Drafting Process to help commenters understand the SDT approach to comments made, and can affect subsequent comments submitted. Peak encourages NERC to post a “consideration of comments” from all comment periods.

In Attachment 2 under I: Design bullet 6, it states that the effects of future BES modifications… this seems to go outside of the scope of the operating horizon on which the RC is focused.

Response: Thank you for your comments.

The drafting team did not post a response to comments received during the informal posting. The drafting team did consider all of the comments in developing draft 1 of the standard subsequently posted in August.

Attachment 2 is a checklist of reliability-related considerations for the Reliability Coordinator (RC) to review that is based on Attachment 1 information provided by the RAS-entity. The RC is not expected to perform planning analysis but to review the information provided and assess whether future BES modifications have been adequately considered in the RAS design. Furthermore, the RC may request assistance in RAS reviews from other parties such as the PC or regional technical groups if necessary. The drafting team declines to modify this bullet in Attachment 2.

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Answer Comment:

In the Rationale for Requirement R1, the last sentence of the first paragraph is “A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality.” How will “any modification to a RAS beyond the replacement of components” preserve the original functionality? The term “functional modification” requires clarification. Suggest developing a formal definition:

RAS Functional Modification--a change to the resultant action for which a RAS is designed.

Rationale for Requirement R8--We agree with segmented testing. However, the requirement does not state this and implies an overall test should still be performed.

R8 currently states:

“At least once every six-calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components.”

Suggest revising to:

“At least once every six-calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. This test can be either:

- An end to end test encompassing all components and testing actual functionality
- A segmented test to test all the components by grouping them together into blocks until all parts of the RAS have been tested”

Additional information in the Technical Guideline may be required to explain how the six year cycle is measured when allowing segmented testing. Segmented testing can test all components of an RAS every six years, but an individual component could end up being tested once every 10 years. For example, a RAS is designed so that it is comprised of a segment "A" and a segment "B". Segment "A" is tested in year 1, segment "B" is tested in year 5. As per Requirement R8, the RAS has been tested within "six-calendar years." The clocks starts for the next functional test period and segment "B" is tested in year 1 (one year since its first test) and segment "A" tested in year 5 (nine years since its first test). The RAS was tested within the "six-calendar years", but segment "A" had a nine year interval. Is this what is intended?

The RAS-owner should be included in Attachment 3.

Response: Thank you for your comments.

The drafting team provided additional clarity for the term "functional modification" in the Rationale. Functional modifications consist of any of the following:

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

Several additional examples are included in the Supplementary Material.

The drafting team declines to add the suggested language to the requirement. The objective of the requirement is to test the overall performance of a RAS. This can be accomplished by several methods. The drafting team is not specifying the method, only the reliability objective. The drafting team revised the Rationale and Supplemental Material to provide additional clarity. The drafting team declines to add the suggested language to the requirement: however, the team will include that in the RSAW for PRC-012, Requirement R8.

The drafting team received multiple comments seeking clarification relating to the RAS-entity/owner. The drafting team modified the Applicability section, consolidated the former terms RAS-entity and RAS-owner, and revised the requirements to address these comments.

Mike Smith - Manitoba Hydro - 1 -

Answer Comment:

1. Regarding R1, it is not clear what the term “Functionally Modified” means. “A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality” does not make sense. Does changing some overall scheme's functional logic without replacing any hardware device qualify as “Functional Modified”?

2. R2 should be changed to “Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1, shall, within four-full-calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback including any identified reliability issues to the RAS-entity”.

3. R3 should be changed to “Following the review performed pursuant to Requirement R2 and receiving the feedback from the reviewing RC, the RAS-entity shall address each identified issue and obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in service or retiring an existing RAS.

4. R5 requires RAS owner to analyze the performance of every RAS operations. It is not clear how much detail is required in this analysis. For those RAS schemes that operates routinely and regularly as designed, is a declaration of correct operation sufficient analysis?

5. R6 should be changed to “Within six-full-calendar months of identifying or being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS-owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)”.

Response: Thank you for your comments.

The drafting team provided additional clarity for the term “functional modification” in the Rationale. Functional modifications consist of any of the following:

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

Several additional examples are included in the Supplementary Material.

The drafting team agrees and made the suggested change to Requirement R2.

The drafting team agrees and made the suggested change to Requirement R3. Please see the revised requirements and complementary revisions to the measures, rationale boxes, supplemental materials, and Attachments.
The drafting team revised the standard such that Requirement R5 only requires a RAS-entity to provide the results of RAS operational performance analysis to the RC if deficiencies were identified. Please see the revised requirements

and complementary revisions to the measures, rationale boxes, supplemental materials, and Attachments. The RAS-entity must verify that the RAS operated correctly; i.e., that Part 5.1 was satisfied.

The drafting team revised Requirement R6 such that it is in line with your suggestion.

Erika Doot - U.S. Bureau of Reclamation - 5 -

Answer Comment:

Reclamation suggests that the drafting team remove Generator Owners from the applicability section of the standard. Reclamation is unclear on how a Generator Owner could be considered to own all or part of a RAS. Reclamation does not believe that Generator Owners are well situated to analyze system-level RAS impacts or be considered a RAS-entity.

Reclamation believes that a list of elements that may constitute remedial action scheme elements would be helpful for understanding the scope of the standard. Project 2010-05.2, Phase 2 of Protection Systems, defines RAS by listing elements which do not individually constitute RAS. Reclamation is unclear on whether only protection system elements are intended to be considered part of a RAS, or whether elements affected by RAS operation like transmission lines or generators may also be considered RAS elements. Reclamation suggests the inclusion of a guidelines and technical basis section that better defines the parameters of RAS that must be analyzed under R4 and R6, and their relationship to system elements affected by RAS.

Reclamation also suggests that the RAS-entity should be responsible for the R5 analysis of each RAS operation or each failure of a RAS to operate. As written, the requirement would impose duplicative analysis requirements upon RAS owners that would not result in a corresponding reliability benefit. In addition, Reclamation believes that requiring each RAS-owner to conduct an analysis of each RAS operation is unwarranted because owners of one component of a RAS, such as a Generator Owner, would not be in the best position to analyze the RAS operation or its impact on the system. The RAS-entity is the RAS-owner designated to represent all RAS-owners for coordinating the review and approval of a RAS. As outlined in the Technical Justifications, "[t]he purpose of the RAS-entity is to be the single information conduit with each reviewing Reliability Coordinator (RC) for all RAS-owners for each RAS." Reclamation believes the RAS analysis requirement should apply to the entity best situated to analyze the overall RAS operation, the RAS-entity.

Finally, Reclamation suggests that the RAS-entity should be responsible for the R8 functional test of each RAS that is required at least once every six calendar years. A RAS-owner responsible for limited RAS components would not be able to verify the overall RAS performance. The RAS-entity should be responsible for coordinating a functional test with all RAS-owners.

Response: Thank you for your comment.

The drafting team declines to make the suggested change removing the GO. Given the critical nature of RAS, all RAS ownership must be accounted for in order to ensure BES reliability.

The drafting team maintains that the team should not attempt to develop an exhaustive list of RAS components. An exhaustive list of components is not practical given the variety that could be applied in RAS design and implementation. See Item 4a in the Implementation Section of Attachment 1 in the Supplemental Material section for typical RAS components for which redundancy may be considered. The RAS-entity should have a clear understanding of what components were applied to put a RAS into service and which were already present in the system before a RAS was installed. The RC will make the final determination regarding which components should be regarded as RAS components during its review.

The drafting team revised the standard such that Requirement R5 applies to the RAS-entity. The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. As explained in the Technical Justification, each separate RAS-entity is obligated to participate in various activities, as identified by the Requirements to the extent of their ownership. It is not the intent of the drafting team, however, to specify how multiple RAS-entities will coordinate.

Each separate RAS-entity is obligated to participate in various activities, as identified by the Requirements to the extent of their ownership.

Anthony Jablonski - ReliabilityFirst - 10 -

Answer Comment: 1. Applicability Section:

i. ReliabilityFirst believes the “RAS-entity” functional entity under the “Applicability” section may cause issues regarding which entity is responsible for requirements related to the “RAS-entity”. Absent any requirements requiring the RAS-owners to designate and make known the official RAS-entity, it may be difficult to assess compliance on the

RAS-entity. ReliabilityFirst recommends including a new Requirement R1 as follows:

a. R1. For each RAS that is owned by multiple RAS-owners, the RAS-owners shall designate one RAS-entity and inform the Reliability Coordinator(s) and Transmission Planner(s) that coordinates the area(s) where the RAS is located of such designation

2. Requirement R5

i. As written, if there are multiple RAS-owners of a RAS, the expectation is to have multiple analyses performed. ReliabilityFirst believes it would be more appropriate to require the RAS-entity to perform one analysis with coordination of all associated RAS-owners.

3. Requirement R8

i. Requirement R8 requires each RAS-owner to perform a functional test of each RAS. As written, in the case where multiple RAS-owners own a single RAS, multiple tests of the same RAS would be required to be run. ReliabilityFirst believes in cases where a RAS is owned by multiple RAS-owners, a single test should be required by the designated RAS-entity in conjunction with all the RAS-owners.

4. VSL for Requirement R4

i. The time frames for the VSL for Requirement R4 are not all inclusive. For example, the Lower VSL states "less than 61-fullcalendar months" while the moderate VSL states "greater than 61-full-calendar months". In this example it is unclear which VSL category an entity falls under if they perform the evaluation in 61 months. Listed below is an example of the Lower VSL for the SDT's consideration.

a. The Transmission Planner performed the evaluation in accordance with Requirement R4, but in greater than 60-full-calendar months but less than **[or equal to]** 61-fullcalendar months.

5. VSL for Requirement R7

i. The Lower VSL states that if an entity failed both 7.2 and 7.3 they would fall under the Lower category. ReliabilityFirst questions what VSL an entity would fall under in the scenario where an entity is compliant with 7.2 but not 7.3?

▪ The RAS-owner implemented a CAP (Part 7.1), but failed to update the CAP (Part 7.2) if actions or timetables changed **[OR]** failed to notify one or more of the reviewing Reliability Coordinator(s) (Part 7.3), in accordance with Requirement R7.

Response: Thank you for your comments.

The drafting team disagrees with your proposed changes. The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. As explained in the Technical Justification, each separate RAS-entity is obligated to participate in various activities, as identified by the Requirements to the extent of their ownership. It is not the intent of the drafting team, however, to specify how multiple RAS-entities will coordinate.

The drafting team corrected the VSLs for Requirements R4 and R7.

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Answer Comment:

Requirement R5: The SRC agrees that the RAS entity should evaluate RASs under the circumstances identified in Requirement R5, but would suggest that such entities be required to provide the results of such assessments to their Reliability Coordinator ***and Planning Coordinator***.

Requirement R9: In conjunction with the comment provided under Q2 to replace the TP with the PC, while the SRC agrees that the RC is the appropriate entity to maintain the database, it suggests that the Reliability Coordinator be required to share its database with the applicable Planning Coordinator(s) as some entities may have a need for planned RAS information for modeling and to ensure that appropriate information is shared across the long- and short-term horizons.

Response: Thank you for your comments.

The drafting team revised Requirement R5 such that the RAS-entity provides the results of RAS operational performance analyses that identified any deficiencies to the RC. The RAS-entity would be expected to engage other parties such as its Transmission Planner or Planning Coordinator as necessary to develop a CAP in response to a RAS for which performance issues were identified. The drafting team declines to make the change.

The rationale for Requirement R9 states: The database enables the RC to provide other entities high-level information on existing RAS that can potentially impact operational and/or planning activities of an entity. The drafting team declines to make the suggested change.

Likes:	1	Electric Reliability Council of Texas, Inc., 2, Axson Elizabeth
Dislikes:	0	

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Answer Comment: Entergy supports the SERC PCS comments on this standard.

Response: Please see the drafting team's responses to the referenced comments.

Mark Kenny - Eversource Energy - 3 -

Answer Comment:

Regarding the Applicability Section 4.1.4 for the RAS-entity, who designates the RAS-owner to represent all RAS-owner(s)?

In the Rationale for Requirement R1, last sentence of the first paragraph, "A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality." How will "any modification to a RAS beyond the replacement of components" preserve the original functionality? Functional modification requires clarification. Suggest developing a formal definition:

RAS Functional Modification--a change to the resultant action for which a RAS is designed.

Rationale for Requirement R8--We agree with segmented testing. However, the requirement does not state this and implies an overall test should still be performed.

R8 currently states:At least once every six-calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components.

Suggest revising to: At least once every six-calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. This test can be either:

o An end to end test encompassing all components and testing actual functionality

o A segmented test to test all the components by grouping them together into blocks until all parts of the RAS have been tested

Additional information in the Technical Guideline may be required to explain how the six year cycle is measured when allowing segmented testing. Segmented testing can test all components of an RAS every six years, but an individual component could end up being tested once every 10 years. For example, a RAS is designed so that it is comprised of a segment "A", and a segment "B". Segment "A" is tested in year 1, segment "B" is tested in year 5. As per Requirement R8 the RAS has been tested within "six-calendar years." The clocks starts for the next functional test period, and segment "B" is tested in year 1 (one year since its first test), and segment "B" tested in year 5 (nine years since its first test). The RAS was tested within the "six-calendar years", but segment "B" had a nine year interval. Is this what is intended?

The RAS-owner should be included in Attachment 3.

R8 and guidance provided in the supplemental material as written appears to overstep the direction provided by the SAR which states that the standard will address maintenance and testing on non-Protection System components of a RAS. Maintenance of Protection Systems installed as a RAS for BES reliability is clearly covered in PRC-005. NPCC is very concerned that there are different timeframes and duplicative testing for RAS components. In particular, the supplemental material provided is very confusing and appears to suggest duplicative testing compared to testing already required in PRC-005. NPCC suggests that all testing requirements for RAS should be contained in one standard.

NPCC suggests deletion of the phase “including any identified deficiencies” in R5 because requirements R5.1 through R5.4 clearly define the necessary level of analysis required by the RAS-owner. Leaving this phrase in will lead to confusion over whether the proper operation of a “composite” RAS is considered a deficiency if one of the two redundant RAS suffer a component failure.

Response: Thank you for your comments.

The drafting team received multiple comments seeking clarification relating to the RAS-entity/owner. The drafting team modified the Applicability section, consolidated the former terms RAS-entity and RAS-owner, and revised the requirements to address these comments.

The drafting team provided additional clarity for the term “functional modification” in the Rationale. Functional modifications consist of any of the following:

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

Several additional examples are included in the Supplementary Material.

The drafting team declines to add the suggested language to the requirement. The objective of the requirement is to test the overall performance of a RAS. This can be accomplished by several methods. The drafting team is not specifying the method, only the reliability objective. The drafting team revised the Rationale and Supplemental Material to provide additional clarity. The drafting team declines to add the suggested language to the requirement: however, the team will include that in the RSAW for PRC-012, Requirement R8.

A more detailed description of the test intervals is now included in the Rationale and Supplementary Material. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. The objective of the requirement is to test the overall performance of a RAS. This can be accomplished by several methods. The drafting team is not specifying the method, only the reliability objective. The drafting team revised the Rationale and Supplemental Material to provide additional clarity.

The drafting team regrets any confusion caused by the examples included in the supplemental material. The supplemental material has been revised to better demonstrate the relationship between PRC-005 component testing and PRC-012-2 functional testing. The drafting team disagrees with the addition of functional testing to PRC-005. Requirement 8 in PRC-012-2 is only applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers, that have no applicability within PRC-005. The Protection System definition used within PRC-005 ensures BES reliability through component testing to verify each component's ability to operate. Functional testing is not an activity in PRC-005. The drafting team chose functional testing to emphasize the logic and control functions of RAS and contends that functional testing of the non-Protection System RAS components in PRC-012-2 complements the component testing of PRC-005. The drafting team revised the standard to allow RAS that have limited impact to have functional testing intervals of up to twelve full calendar years. However, the drafting team contends that the six full calendar year interval is appropriate for the higher impact RAS given the potential negative impact to BES reliability should a RAS operate incorrectly. Existing regional practices include more frequent RAS functional testing than the proposed six full calendar year interval.

Requirements R5.1.1 through 5.1.4 (R5.1 through R5.4 in the previously posted draft of PRC-012-2) state the scope of the RAS operational performance, and therefore any "deficiencies" identified and reported to the RC per Requirement R5.2 are with respect to these. The drafting team contends that if the RAS appropriately triggers for the system conditions for which it was designed, and provides the desired response as designed, that a component failure in one of two redundant RAS would not constitute a deficiency with respect to the operational analysis described in Requirement R5. It would be expected, however, that if such a component failure was identified, the RAS-entity would be incented to repair the failed component as soon as possible to avoid the risk of the RAS failing to operate for a future event. The drafting team declines to make the suggested change.

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Answer Comment: Attachment 1, Section III-Implementation states, "5. Documentation describing the functional testing process." Dominion recommends deleting this bullet. This information is not necessarily available during

	the preliminary design phase. The approval of the design is sought prior to detailed engineering. (Planning) In R5 it states that the RAS owner analyzes the event, but in flow chart it states RAS owner and TP. Dominion suggests that the content in the Flow Chart be consistent with language of the Requirement. R5 references the timeframe “within 120 calendar days”, however in other areas of the document the time frame is stated to be “within XX calendar months”. Dominion suggests updating the document to reflect the actual timeframe. Dominion also believes consistency is needed and suggests the timeframes reflect "full calendar months” versus “months”.

Response: Thank you for your comments.

Thank you for your comment. The drafting team contends that sufficient information be provided to the RC to allow a proper review including information describing the RAS-entity’s plan for periodic testing. The drafting team declines to make the suggested change.

The drafting team revised the Flowchart.

The drafting team added “mutually agreed upon schedule” to allow more time for the RAS operational analysis to be performed and added the modifier “full” to calendar days. The timeframe of 120 full calendar days is consistent with a similar requirement in PRC-004-5.

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Answer Comment:

1. In addition to RAS-entity's, RAS-owners also have compliance obligations. Yet RAS-owners are not identified in any of the attachments. In addition, the RAS-related equipment of each owner should be identified in one attachment for use by the Reliability Coordinator, the Transmission Planner, and the Compliance Enforcement Authority. Expanding Attachment 3 may be the most efficient way to address these concerns.

2. R5 should be modified by changing this phrase: "…analyze the RAS performance…" to "analyze the performance of its RAS-related equipment." In cases where there are multiple RAS owners, a single RAS-owner cannot analyze the performance of the entire RAS; it can only analyze the performance of its own RAS-related equipment.

Response: Thank you for your comments.

The drafting team received multiple comments seeking clarification relating to the RAS-entity/owner. The drafting team consolidated the former terms RAS-entity and RAS-owner in the Applicability section, revised the requirements and Supplemental Material section of the standard to address these comments.

The drafting team maintains that the team should not attempt to develop an exhaustive list of RAS components. An exhaustive list of components is not practical given the variety that could be applied in RAS design and implementation. See Item 4a in the Implementation Section of Attachment 1 in the Supplemental Material section for typical RAS components for which redundancy may be considered. The RAS-entity should have a clear understanding of what components were applied to put a RAS into service and which were already present in the system before a RAS was installed. The RC will make the final determination regarding which components should be regarded as RAS components during its review.

Each separate RAS-entity is obligated to participate in various activities, as identified by the Requirements to the extent of their ownership. The drafting team revised the Rationale and Supplemental Material to provide additional clarity.

Likes:	4	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla PSEG - PSEG Fossil LLC, 5, Kucey Tim PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
Dislikes:	0	

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Answer Comment:

FirstEnergy would like additional clarification on the phrase "RAS controller" in the second paragraph of the Supplemental Material section in "Applicability", 4.1.4 RAS-entity.

Additionally, FirstEnergy seeks to confirm that if a RAS system operates as planned/designed durnng normal operations then can the data from this actual operation be used to verify/satisfy testing requirements?

Response: Thank you for your comments.

The drafting team received multiple comments seeking clarification relating to the RAS-entity/owner. The drafting team consolidated the former terms RAS-entity and RAS-owner in the Applicability section, revised the requirements and Supplemental Material section of the standard to address these comments.

The drafting team added the language to the measure for Requirement 8 indicating that a correct operation of a RAS segment would qualify as a functional test for that segment. In addition, the team will include that in the RSAW for PRC-012, Requirement R8.

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2

Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1

Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Answer Comment:

Because feeder loading can be changed intentionally, it is frequent to add, substitute, or remove load tripping devices (not distributed relays) in order to maintain the amount of load that is required by a load tripping RAS. Would these changes constitute a RAS functional modification? If so, suggest revising the definition of RAS functional modification. The Attachment 1 procedure that would have to be applied would be overly burdensome.

Regarding the Applicability Section 4.1.4 for the RAS-entity, who designates the RAS-owner to represent all RAS-owner(s)?

In the Rationale for Requirement R1, last sentence of the first paragraph, "A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality." How will "any modification to a RAS beyond the replacement of components" preserve the original functionality? Functional modification requires clarification. Suggest developing a formal definition:

RAS Functional Modification--a change to the resultant action for which a RAS is designed.

Rationale for Requirement R8--We agree with segmented testing. However, the requirement does not state this and implies an overall test should still be performed.

R8 currently states:

At least once every six-calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components.

Suggest revising to:

At least once every six-calendar years, each RAS-owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. This test can be either:

o An end-to-end test encompassing all components and testing actual functionality

o A segmented test to test all the components by grouping them together into blocks until all parts of the RAS have been tested

Additional information in the Technical Guideline may be required to explain how the six year cycle is measured when allowing segmented testing. Segmented testing can test all components of an RAS every six years, but an individual component could end up being tested once every 10 years. For example, a RAS is designed so that it is comprised of a segment “A”, and a segment “B”. Segment “A” is tested in year 1, segment “B” is tested in year 5. As per Requirement R8 the RAS has been tested within “six-calendar years.” The clock starts for the next functional test period, and segment “B” is tested in year 1 (one year since its first test), and segment “A” tested in year 5 (nine years since its first test). The RAS was tested within the “six-calendar years”, but segment “A” had a nine year interval. Is this what is intended? It should be required that all segments be tested in the same calendar year.

The RAS-owner should be included in Attachment 3.

Requirement R8 and guidance provided in the supplemental material as written go beyond the direction stipulated by the SAR which states that the standard will address maintenance and testing on non-Protection System components of a RAS. Maintenance of Protection Systems installed as a RAS for BES reliability is clearly covered in PRC-005. We are very concerned that there are different timeframes and duplicative testing for RAS components. In particular, the supplemental material provided is very confusing and appears to suggest duplicative testing compared to testing already required by PRC-005. Suggest that all testing requirements for RAS should be contained in one standard. The testing time periods should be made consistent with Table 1-1 in PRC-005, specifically 6 years for an unmonitored protection system, and 12 years for an unmonitored microprocessor protection system.

NPCC suggests deletion of the phase “including any identified deficiencies” in R5 because Parts 5.1 through 5.4 clearly define the necessary level of analysis required by the RAS-owner. Leaving this phrase in will lead to confusion over whether the proper operation of a "composite" RAS is considered a deficiency if one of the two redundant RAS suffer a component failure.

In C. Compliance, Section 1.2 Evidence Retention: the RC and TP have not been included. The TO, GO and DP are requested to keep data for requirements that they might not be responsible for.

Response: Thank you for your comments.

The drafting team provided additional clarity for the term "functional modification" in the Rationale. Functional modifications consist of any of the following:

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

Several additional examples are included in the Supplementary Material.

A more detailed description of the test intervals is now included in the Rationale and Supplementary Material. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment.

The drafting team consolidated the former terms RAS-entity and RAS-owner in the Applicability section, revised the requirements and Supplemental Material section of the standard to address these comments.
The functional testing of a RAS to verify its performance is different from the maintenance activities associated with the Protection System Components as detailed in the tables of PRC-005. Requirement 8 of PRC-012-2 is only

applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers and are not Protection System Components and as such, do not belong in PRC-005. The Protection System definition used within PRC-005 ensures BES reliability through component testing to verify each component's ability to operate. Functional testing is not an activity in PRC-005. The drafting team chose functional testing to emphasize the logic and control functions of RAS. The drafting team contends that functional testing of the non-Protection System RAS components in PRC-012-2 complements the component testing of PRC-005.

Requirements R5.1.1 through 5.1.4 (R5.1 through R5.4 in the previously posted draft of PRC-012-2) state the scope of the RAS operational performance, and therefore any "deficiencies" identified and reported to the RC per Requirement R5.2 are with respect to these. The drafting team contends that if the RAS appropriately triggers for the system conditions for which it was designed, and provides the desired response as designed, that a component failure in one of two redundant RAS would not constitute a deficiency with respect to the operational analysis described in Requirement R5. It would be expected, however, that if such a component failure was identified, the RAS-entity would be incented to repair the failed component as soon as possible to avoid the risk of the RAS failing to operate for a future event. The drafting team declines to make the suggested change.

The drafting team declines to add the suggested language to the requirement. The objective of the requirement is to test the overall performance of a RAS. This can be accomplished by several methods. The drafting team is not specifying the method, only the reliability objective. The drafting team revised the Rationale and Supplemental Material to provide additional clarity.

The drafting team regrets any confusion caused by the examples included in the supplemental material. The supplemental material has been revised to better demonstrate the relationship between PRC-005 component testing and PRC-012-2 functional testing. The drafting team disagrees with the addition of functional testing to PRC-005. Requirement 8 in PRC-012-2 is only applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers, that have no applicability within PRC-005. The Protection System definition used within PRC-005 ensures BES reliability through component testing to verify each component's ability to operate. Functional testing is not an activity in PRC-005. The drafting team chose functional testing to emphasize the logic and control functions of RAS and contends that functional testing of the non-Protection System RAS components in PRC-012-2 complements the component testing of PRC-005. The drafting team revised the standard to allow RAS that have limited impact to have functional testing intervals of up to twelve full calendar years. However, the drafting team contends that the six full calendar year interval is appropriate for the higher impact RAS given the potential negative impact to BES reliability should a RAS operate incorrectly. Existing regional practices include more frequent RAS functional testing than the proposed six full calendar year interval.

The Compliance section has been modified to correct the issues you identified.

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Answer Comment:	Tacoma Power recommends that the definition of 'RAS-owner' be limited to functional ownership, as opposed to component ownership. For example, if one company owns a station DC supply, some wiring, and trip coil, but another company owns the control device at the same location, the entity that owns the control device should be a RAS-owner, and the entity that owns the station DC supply, wiring, and trip coil should not be a RAS-owner. Another example would be an entity that owns sensing devices that another entity uses to provide inputs to a relay or PLC that it owns; the entity that owns the sensing devices in this example should not be a RAS-owner. Yet another example is when one entity owns a portion of the communications system; simply owning part of the communications system should not make the entity a RAS-owner. In the Q & A document, section 9, top of page 6, what if timing is only critical on the order of minutes (e.g., remediation of thermal

overload). Could replacement of a T1 multiplexor possibly not be considered a RAS functional change in this case?

In the Q & A document, section 9, page 6, the example of “replacement of a failed RAS component with an identical component” seems overly exclusive. It is recommended to replace “identical” with “substantially identical.”

In Requirement R6, why is “six-full calendar months,” instead of simply “six calendar months,” used?

In the Supplemental Material section, page 27, the following sentence has a grammatical/mechanical issue: “A RAS is only allowed to drop non-consequential load or interrupt Firm Transmission Service can do that only if that action is allowed for the Contingency for which it is designed.”

In the Supplemental Material section, page 28, the following passage does not seem to read well: “These changes could result in inadvertent activation of that output, therefore, tripping too much load and result in violations of Facility Ratings. Alternatively, the RAS might be designed to trip more load than necessary (i.e., “over trip”) in order to satisfy single-component-failure requirements. System changes could result in too little load being tripped at affected locations and result in unacceptable BES performance if one of the loads failed to trip.” Should the middle sentence be removed? It seems incongruous with the other two sentences.

In the Supplemental Material section, page 29, would a CAP be required if equipment fails that is readily replaceable/repairable? Tacoma Power maintains that CAP's should be required for issues that will require a longer time to address. In general, notification of RAS equipment failures is addressed by other standards.

In the Supplemental Material section, page 30, change "the , the" to "then, the."

Response: Thank you for your comments.

The drafting team disagrees with your proposed change. The drafting team contends that basing RAS ownership on function rather than components could lead to reliability gaps. The RAS-entity owns the facilities, and as the asset owner is responsible for the purchase, design, operation, and testing of a RAS. The drafting team contends your examples strengthen the case for the asset owner to be the responsible entity.

The drafting team modified the example in the Q & A document of replacing a T1 multiplexor to indicate that a resulting change in timing would be a functional modification only if it may be important to the timing of the RAS.

The drafting team added ". . . , or a component that uses the same functionality as the failed component." Other examples were also added to the Supplementary Material.

The "full" allows any fractional month, possibly adding as much as another month.

The drafting team revised the sentence.

The drafting team modified the wording of this section for clarity.
The drafting team contends that even a RAS equipment failure that is readily replaceable/repairable should be documented. Such a CAP may be as simple as an email to the RC to the effect of "Found failed auxiliary relay. Replaced failed auxiliary relay with a spare. Repairs completed on [date]."

The drafting team made the editorial change.

Eric Olson - Transmission Agency of Northern California - 1 -

Answer Comment:

Although neither the Applicability section nor the Requirements of this draft standard distinguish between Protection System components and non-Protection System components of a RAS, the associated supporting information does make such a distinction. For example, the first paragraph of the Background Information section on the Unofficial Comment Form includes the following:

"The maintenance of the Protection System components associated with RAS (PRC-017-1 Remedial Action Scheme Maintenance and Testing) are already addressed in PRC-005. PRC-012-2 addresses the testing of the non-Protection System components associated with RAS/SPS."

NERC's supporting information elsewhere suggests that examples of non-Protection System components include programmable logic controllers, computers, and the control functions of microprocessor relays.

Based on TANC's understanding of NERC's intent for this standard, we suggest that NERC modify the definition of RAS-owner that is provided in the standard's Applicability section to the following.

"RAS-owner - the Transmission Owner, Generator Owner, or Distribution Provider owns all or part of ***the non-Protection System components of*** *a*

RAS" (bold text is added to current proposed definition).

TANC's proposed modified definition would clarify that this standard and its requirements are not applicable to a Transmission Owner, Generator Owner, or Distribution Provider that doesn't own any non-Protection System components of a RAS.

Response: Thank you for your comment.

The drafting team declines to make the suggested change. The drafting team consolidated the former terms RAS-entity and RAS-owner in the Applicability section, revised the requirements and Supplemental Material section of the standard to address these comments.

Leonard Kula - Independent Electricity System Operator - 2 -

Answer Comment:

Requirement R9: In conjunction with our comment under Q2 to replace TP with PC, while we agree that the RC is the appropriate entity to maintain the database, we suggest adding the Planning Coordinator to this requirement for RASs that have been planned and evaluated in the long-term planning timeframe. Some entities may have a need for planned RAS information for modeling.

We recommend that the standard should recognize that all RAS are not equal and therefore should not need the same level of design review (as per R1), performance requirement in case of RAS failure (as per 4.4), and operation analysis (as per R5). We suggest defining two or more "class" or "type" for RAS based on the impact of their misoperation or failure to operate on the system performance. Different class or type of RAS will then have different levels of design, performance and analysis requirements.

R8 and guidance provided in the supplemental material as written appears to overstep the direction provided by the SAR which states that the standard will address maintenance and testing on non-Protection System components of a RAS. Maintenance of Protection Systems installed as a RAS for BES reliability is clearly covered in PRC-005. The IESO is very concerned that there are different timeframes and duplicative testing for RAS components. In particular, the supplemental material provided is very confusing and appears to suggest duplicative testing compared to testing already required in PRC-005. The IESO suggests that all testing requirements for RAS should be contained in one standard. NERC PRC-005 applies to Protection Systems installed as Remedial Action Schemes for BES reliability. As such, all RAS Protective Relays, Communication Systems, Voltage and Current Sensing Devices Providing Inputs to Protective Relays, Control Circuitry, DC Supply, alarms and Automatic Reclosing Components are already included in PRC-005. Lastly, this requirement would force entities to perform testing on local area schemes; yet non-BES components are not subject to maintenance requirements under NERC PRC-005. Typing would be a good mythology to distinguish which RAS schemes should be subject to the strict maintenance requirements.

The IESO suggests deletion of the phase “including any identified deficiencies” in R5 because requirements R5.1 through R5.4 clearly define the necessary level of analysis required by the RAS-owner. Leaving this phrase in will lead to confusion over whether the proper operation of a "composite" RAS is considered a deficiency if one of the two redundant RAS suffer a component failure.

Response: Thank you for your comments.

The drafting team declines to make the suggested change. The drafting team contends that other NERC standards provide adequate methods to assure data sharing among entities with a reliability need.

The drafting team included a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process.

The drafting team regrets any confusion caused by the examples included in the supplemental material. The supplemental material has been revised to better demonstrate the relationship between PRC-005 component testing and PRC-012-2 functional testing. The drafting team disagrees with the addition of functional testing to PRC-005. Requirement 8 in PRC-012-2 is only applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers, that have no applicability within PRC-005. The Protection System definition used within PRC-005 ensures BES reliability through component testing to verify each component's ability to operate. Functional testing is not an activity in PRC-005. The drafting team chose functional testing to emphasize the logic and control functions of RAS and contends that functional testing of the non-Protection System RAS components in PRC-012-2 complements the component testing of PRC-005. The drafting team revised the standard to allow RAS that have limited impact to have functional testing intervals of up to twelve full calendar years. However, the drafting team contends that the six full calendar year interval is appropriate for the higher impact RAS given the potential negative impact to BES reliability should a RAS operate incorrectly. Existing regional practices include more frequent RAS functional testing than the proposed six full calendar year interval.

Requirements R5.1.1 through 5.1.4 (R5.1 through R5.4 in the previously posted draft of PRC-012-2) state the scope of the RAS operational performance, and therefore any "deficiencies" identified and reported to the RC per Requirement R5.2 are with respect to these. The drafting team contends that if the RAS appropriately triggers for the system conditions for which it was designed, and provides the desired response as designed, that a component failure in one of two redundant RAS would not constitute a deficiency with respect to the operational analysis described in Requirement R5. It would be expected, however, that if such a component failure was identified, the RAS-entity would be incented to repair the failed component as soon as possible to avoid the risk of the RAS failing to operate for a future event. The drafting team declines to make the suggested change.

Richard Vine - California ISO - 2 -

Answer Comment:	The California ISO supports the comments of the ISO/RTO Standards Review Committee

Response: Please see the drafting team's responses to the referenced comments.

Jamison Cawley - Nebraska Public Power District - 1 -

Answer Comment:	The second version of PRC-005 was intended to include all testing and maintenance requirements from PRC-017, and facilitate the retirement of PRC-017. Requirement 8 of the current draft of this standard (PRC-012-2) includes testing and maintenance requirements related to those found in PRC-017-0. Additionally, Requirement 8 of PRC-012-2 expands

on those found in PRC-017-0 by including non-Protection System components. We feel this requirement should not be included in PRC-012-2, and we request a clear description of the differences of the intended purpose of the proposed PRC-012-2 Requirement 8 and that of PRC-017-0/PRC-005-2. Furthermore, the remaining requirements of PRC-012-2 seem to be primarily focused on system planning, and consideration should be given to moving these to the TPL standard family.

Response: Thank you for your comments.

The functional testing of a RAS to verify its performance is different from the maintenance activities associated with the Protection System Components as detailed in the tables of PRC-005. Requirement 8 of PRC-012-2 is only applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers and are not Protection System Components and as such, do not belong in PRC-005. The Protection System definition used within PRC-005 ensures BES reliability through component testing to verify each component's ability to operate. Functional testing is not an activity in PRC-005. The drafting team chose functional testing to emphasize the logic and control functions of RAS. The drafting team contends that functional testing of the non-Protection System RAS components in PRC-012-2 complements the component testing of PRC-005.

The work performed by the drafting team is in response to the SPCS/SAMS report "Special Protection Systems (SPS) and Remedial Action Schemes (RAS): Assessment of Definition, Regional Practices, and Application of Related Standards". This report recommends "Project 2010-05.2 should consolidate the requirements pertaining to review, assessment, and documentation of SPS into one standard that includes continent-wide procedures for reviewing new or modified SPS, for assessing existing SPS in annual transmission planning assessments, and for periodic comprehensive SPS assessments. The project also should revise requirements pertaining to analysis and reporting of SPS misoperations in a revision of standard PRC-016-0.1." The resulting SAR for aligns with this recommendation and would require the Standard process to re-start with a new SAR. The drafting team maintains this is not necessary and the Reliability objective of the SPCS/SAMS report can be met with PRC-012-2.

Likes:	1	Nebraska Public Power District, 3, Eddleman Tony
Dislikes:	0	

Andrew Gallo - Austin Energy - 6 -

Answer Comment:	City of Austin dba Austin Energy suggests the SDT add clarifying language to R8 to account for a RAS-owner who owns only part of a RAS. In doing so, the SDT may need to consider how a partial RAS-owner will be able "to verify the overall RAS performance."

Response: Thank you for your comment.

The drafting team consolidated the former terms RAS-entity and RAS-owner in the Applicability section, revised the requirements and Supplemental Material section of the standard to address these comments. The drafting team revised the requirement to state that each RAS-entity shall participate in the testing in order to assure accountability for proper testing of each RAS. As explained in the Technical Justification, each separate RAS-entity is obligated to participate in various activities, as identified by the Requirements to the extent of their ownership. It is not the intent of the drafting team, however, to specify how the RAS-entities participate.

Dixie Wells - Lower Colorado River Authority - 5 -

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Answer Comment:

To address existing entity NERC registration in the ERCOT region, “Transmission Planner” should be replaced with “Transmission Planner (in the ERCOT Region this applies to the Planning Authority and /or Reliability Coordinator.)”

R4. Each Transmission Planner (in the ERCOT Region this applies to the Planning Authority and /or Reliability Coordinator) shall perform an evaluation of each RAS within its planning area at least once every 60-full-calendar-months and provide the RAS-owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Response: Thank you for your comments.

The drafting team revised the requirement. The Planning Coordinator (PC) is now the entity responsible for the evaluation required per Requirement R4 and is required to provide the results of the RAS evaluation to each reviewing Reliability Coordinator and each impacted Transmission Planner and RAS-entity. The PC is the functional entity best-suited to perform this evaluation because they have a wide-area planning perspective.

Tony Eddleman - Nebraska Public Power District - 3 -

Answer Comment: The second version of PRC-005 was intended to include all testing and maintenance requirements from PRC-017, and facilitate the retirement of PRC-017. Requirement 8 of the current draft of this standard (PRC-012-2) includes testing and maintenance requirements related to those found in PRC-017-0. Additionally, Requirement 8 of PRC-012-2 expands on those found in PRC-017-0 by including non-Protection System components. We feel this requirement should not be included in PRC-012-2, and we request a clear description of the differences of the intended purpose of the proposed PRC-012-2 Requirement 8 and that of PRC-017-0/PRC-005-2. Furthermore, the remaining requirements of PRC-012-2 seem to be primarily focused on system planning, and consideration should be given to moving these to the TPL standard family.

Response: Thank you for your comments.

The functional testing of a RAS to verify its performance is different from the maintenance activities associated with the Protection System Components as detailed in the tables of PRC-005. Requirement 8 of PRC-012-2 is only applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers and are not Protection System Components and as such, do not belong in PRC-005. The Protection System definition used within PRC-005 ensures BES reliability through component testing to verify each component's ability to operate. Functional testing is not an activity in PRC-005. The drafting team chose functional testing to emphasize the logic and control functions of RAS. The drafting team contends that functional testing of the non-Protection System RAS components in PRC-012-2 complements the component testing of PRC-005.

Likes:	1	Nebraska Public Power District, 1, Cawley Jamison
Dislikes:	0	

Don Schmit - Nebraska Public Power District - 5 -

Answer Comment:	The second version of PRC-005 was intended to include all testing and maintenance requirements from PRC-017, and facilitate the retirement of PRC-017. Requirement 8 of the current draft of this standard (PRC-012-2) includes testing and maintenance requirements related to those found in PRC-017-0. Additionally, Requirement 8 of PRC-012-2 expands on those found in PRC-017-0 by including non-Protection System components. We feel this requirement should not be included in PRC-012-2, and we request a clear description of the differences of the intended purpose of the proposed PRC-012-2 Requirement 8 and that of PRC-017-0/PRC-005-2. Furthermore, the remaining requirements of PRC-012-2 seem to be primarily focused on system planning, and consideration should be given to moving these to the TPL standard family.

Response: Thank you for your comments.

The functional testing of a RAS to verify its performance is different from the maintenance activities associated with the Protection System Components as detailed in the tables of PRC-005. Requirement 8 of PRC-012-2 is only applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers and are not Protection System Components and as such, do not belong in PRC-005. The Protection System definition used within PRC-005 ensures BES reliability through component testing to verify each component's ability to operate. Functional testing is not an activity in PRC-005. The drafting team chose functional testing to emphasize the logic and control functions of RAS. The drafting team contends that functional testing of the non-Protection System RAS components in PRC-012-2 complements the component testing of PRC-005.

Likes:	1	Nebraska Public Power District, 1, Cawley Jamison
Dislikes:	0	

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Answer Comment:	Texas RE seeks clarification on the following: • If a RAS is implemented to run-back a generator due to a line loading trigger level, is the Generator Owner a RAS-owner by default? Or is it dependent upon the ownership of the components that are used (e.g., protective or auxiliary relays, communication systems, sensing devices,

station DC, control circuitry, etc.)?

• In Requirement R5, is the responsibility associated with the each RAS-owner correct? Should that responsibility be the RAS-entity (in collaboration with all RAS-owners) to avoid multiple analysis activities which may result in conflicting results and/or CAPs? If one RAS-owner finds a deficiency in another owner's portion of the RAS, how is that notification made?

• In Requirement R5 there is no notification of a deficiency to a RAS-owner. Is notification considered to be when a RAS-owner recognizes a deficiency in its part of the RAS? R6 references a notification but it is not clear in R5.

• Does the SDT consider "arming", whether it signals another party to act or is used in situational awareness, as an integral part of RAS operation? Some RAS designs include an "arming" phase (e.g., A RAS will "arm" if the amperage on line X measure 900 amps. If the amperage measures 920 amps the RAS will activate. In some designs, "arming" may signal action to be taken by another party is needed (e.g. generator runback to level X), and if the action is not taken the RAS may fully activate (e.g. trip generator).) In the Supplemental Material (and somewhat, but not totally, mirrored in the rationale for R5) there is the statement: "A RAS operational performance analysis is intended to: (1) verify RAS operation is consistent with implemented design; or (2) identify RAS performance deficiency(ies) that manifested in the incorrect RAS operation or failure of RAS to operate when expected." Failure of a RAS to arm, if designed to arm, is indicative that the design was improperly implemented.

• In Requirement R8, which entity responsible for coordinating the functional test for a multi-owner RAS that covers a wide area? The segmented approach referred to in the rationale may cover an individual RAS-owner's trip function or communications, but there needs to be an overall functional test of the logic that arms/disarms/activates the RAS, which may involve multiple RAS-owners. Texas RE recommends changing the requirement language to "RAS-owner, or RAS-entity as mutually agreed by the RAS-owners shall…". Also, a functional test should be required if there is a system change that affects one or more Elements that are monitored or operated as part of a RAS, in order to verify any logic changes. Requirements R1-R3 currently do not address functional testing, only the design. Texas RE recommends R8 indicate "proper operation of RAS" elements and not limit the functional test verification to non-Protection System components. Some Protection System components involved in the proper operation of a RAS may have an extended maintenance intervals and the RAS would not be functionally tested without including Protection System components. Overall RAS performance cannot be attained without functionally testing all aspects of the RAS.

Texas RE noticed an inconsistency between the requirement language and the RSAW. The requirement language of Requirement R5 states "Each RAS-owner shall" but the Note to Auditor in the Requirement R5 section of the RSAW indicates that a RAS-entity can provide the analysis. Registered entities are held accountable to the language of the requirement. Introducing the concept of a RAS-entity providing the information adds confusion. If the intent is for both the RAS-Owner and the RAS-entity to be able to analyze RAS performance and provide the results, Texas RE recommends changing the requirement language to

"RAS-owner, or RAS-entity as mutually agreed by the RAS-owners analyze…". Texas RE supports the idea of a RAS-entity doing the analysis.

Additionally, Texas RE recommends a requirement to report the degraded RAS to the RC. Texas RE noticed the referenced Standards/Requirements (i.e., Supplemental Material indicates PRC-001 R6 and TOP-001-2 R5) are either being retired or are not explicit enough to ensure that the reliability of the system is maintained for those who should have situational awareness. This is a perceived gap due to the current steady state of the standards.

Texas RE recommends Attachment 3 include the RAS-owner(s) as well as the RAS-entity. If Requirement R9 is left as "at a minimum", that is all that will be done. Ownership is critical to know because of the responsibilities required in the majority of the Requirements (e.g., How will the TP provide results to owners without knowing all the owners?) The TP does not, generally, know the RAS-owners based on the ownership at the component level.

Response: Thank you for your comments.

The drafting team maintains that the owner of the components in the scenario you describe; e.g., the generator control system would be an owner of the RAS; i.e., a RAS-entity.

The drafting team revised the standard such that Requirement R5 applies to the RAS-entity. The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. As explained in the Technical Justification, each separate RAS-entity is obligated to participate in various activities, as identified by the Requirements to the extent of their ownership. It is not the intent of the drafting team, however, to specify how the RAS-entities participate.

The drafting team revised Requirements R5 and R6.

The drafting team contends that failure of a RAS to arm, if designed to arm, may be indicative that the design was improperly implemented or the RAS did not operate as designed. The event would be handled as a failure to operate, since RAS action should not occur without prior arming, and a CAP developed to resolve the issue pursuant to R6. Any incorrect operation of a RAS, in whole or in part, indicates that the RAS effectiveness and/or coordination has been compromised. The correct operation of a RAS is important for maintaining the reliability and integrity of the BES.

The drafting team revised the requirement to state that each RAS-entity shall participate in the testing in order to assure accountability for proper testing of each RAS. As explained in the Technical Justification, each separate RAS-entity is obligated to participate in various activities, as identified by the Requirements to the extent of their ownership. It is not the intent of the drafting team, however, to specify how the RAS-entities participate. Attachment 1 includes item III. 5 to describe the functional testing process.

The drafting team contends that each owner of a RAS or part of a RAS is a RAS-entity which is responsible for compliance with the requirements of PRC-012. It is not the intent of the drafting team to specify how multiple RAS owners will coordinate. The drafting team believes that it is in the best interest of the BES and the entity to perform a commissioning test, likely to include functional testing when there is a required system change that affects one or more Elements of RAS. The drafting team doesn't dispute the value of functional testing following System changes or RAS logic changes but the standard does not address "commissioning" testing of these changes and contends that is good utility practice but declines to include this in the standard and that adding an additional requirement is unnecessary. The drafting team declines to add an addition requirement to mandate functional testing during RAS changes make the suggested change. The drafting team contends that a "functional test of each RAS to verify the overall RAS performance", as specified in Requirement R8 would include testing of the entire RAS. Requirement R8 specifically requires testing proper operation only of non-Protection System components because Protection System components installed as part of a RAS are already addressed by PRC-005-5.

The drafting team added language to the measure for Requirement 8 indicating that a correct operation of a RAS segment would qualify as a functional test. In addition, the team will include that in the RSAW for PRC-012, Requirement R8. The drafting team's consolidation of RAS-owner and RAS-entity into the single RAS-entity should answer the concern regarding which entity analyzes and reports on RAS operational failures.

The status of a degraded RAS is required to be reported (in Real-time) to the Transmission Operator via PRC-001, Requirement R6, then to the RC via TOP-001-3, Requirement R8. See Phase 2 of Project 2007-06 for the mapping document from PRC-001 to other standards regarding notification of RC by TOP if a deficiency is found during testing. Consequently, it is not necessary to include a similar requirement in this standard.

The drafting team consolidated the former terms RAS-entity and RAS-owner in the Applicability section, revised the requirements and Supplemental Material section of the standard to address these comments.

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Answer Comment:

· Hydro One Networks Inc. recommends that the standard should recognize that all RASs are not equal and therefore, should not be subject to the same level of design review (as per R1), performance requirements in case of RAS failure (as per 4.4), and operation analysis (as per R5). We suggest defining two or more "class" or "type" for RAS based on the impact of their misoperation or failure to operate on the system performance. Different classes or types of RAS will consequently have different levels of design, performance and analysis requirements associated with them. Hydro One Networks Inc. would like to emphasize that in the absence of a means of differentiation (via typing or classes of RAS), utilities will feel compelled to spend significant capital, for little or no material improvement to system reliability.

· Hydro One Networks Inc. believes that requirement R8 and guidance provided in the supplemental material appear to overstep the direction provided by the SAR, which states that the standard will address maintenance and testing on non-Protection System components of a RAS. Maintenance of Protection Systems installed as a RAS for BES reliability is clearly covered in PRC-005. Hydro One Networks Inc. further joins the NPCC with its concern over the different timeframes provided and duplicative testing for RAS components. In particular, the supplemental material provided is very confusing and appears to suggest duplicative testing compared to testing already required in PRC-005. Hydro One Networks Inc. agrees with the NPCC and suggests that all testing requirements for RAS should be contained in one standard. NERC PRC-005 applies to Protection Systems installed as Remedial Action Schemes for BES reliability. As such, all RAS Protective Relays, Communication Systems, Voltage and Current Sensing Devices Providing Inputs to Protective Relays, Control Circuitry, DC Supply, alarms and Automatic Reclosing Components are already included in PRC-005. Lastly, this requirement would force entities to perform testing on local area schemes; yet non-BES components are not subject to maintenance requirements under NERC PRC-005. Typing would be a good mythology to distinguish which RAS schemes should be subject to the strict maintenance requirements.

· Hydro One Networks Inc. also agrees with the NPCC in suggesting the deletion of the phase “including any identified deficiencies” in R5 because requirements R5.1 through R5.4 clearly define the necessary level of analysis required by the RAS-owner. Leaving this phrase in would lead to confusion over whether the proper operation of a "composite" RAS is considered a deficiency if one of the two redundant RAS suffer a component failure.

Response: Thank you for your comments.

The drafting team included a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process.

The functional testing of a RAS to verify its performance is different from the maintenance activities associated with the Protection System Components as detailed in the tables of PRC-005. Requirement 8 of PRC-012-2 is only applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers and are not Protection System Components and as such, do not belong in PRC-005. The Protection System definition used within PRC-005 ensures BES reliability through component testing to verify each component's ability to operate. Functional testing is not an activity in PRC-005. The drafting team chose functional testing to emphasize the logic and control functions of RAS. The drafting team contends that functional testing of the non-Protection System RAS components in PRC-012-2 complements the component testing of PRC-005.

The drafting team included a provision that RAS can be designated as "limited impact" if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. When appropriate, new or functionally modified RAS implemented after the effective date of this standard will be designated as limited impact by the Reliability Coordinator during the RAS review process. Limited impact schemes have a twelve full calendar year functional test interval in Requirement R8.

The drafting team regrets any confusion caused by the examples included in the supplemental material. The supplemental material has been revised to better demonstrate the relationship between PRC-005 component testing and PRC-012-2 functional testing. The drafting team disagrees with the addition of functional testing to PRC-005. Requirement 8 in PRC-012-2 is only applicable to those non-Protective System components used in RAS. The drafting team contends these are the control components, such as programmable logic controllers, that have no applicability within PRC-005. The Protection System definition used within PRC-005 ensures BES reliability through component testing to verify each component's ability to operate. Functional testing is not an activity in PRC-005. The drafting team chose functional testing to emphasize the logic and control functions of RAS and contends that functional testing of the non-Protection System RAS components in PRC-012-2 complements the component testing of PRC-005. The drafting team revised the standard to allow RAS that have limited impact to have functional testing intervals of up to twelve full calendar years. However, the drafting team contends that the six full calendar year interval is appropriate for the higher impact RAS given the potential negative impact to BES reliability should a RAS operate incorrectly. Existing regional practices include more frequent RAS functional testing than the proposed six full calendar year interval.

Requirements R5.1.1 through 5.1.4 (R5.1 through R5.4 in the previously posted draft of PRC-012-2) state the scope of the RAS operational performance, and therefore any "deficiencies" identified and reported to the RC per Requirement R5.2 are with respect to these. The drafting team contends that if the RAS appropriately triggers for the system conditions for which it was designed, and provides the desired response as designed, that a component failure in one of two redundant RAS would not constitute a deficiency with respect to the operational analysis described in Requirement R5. It would be expected, however, that if such a component failure was identified, the RAS-entity would be incented to repair the failed component as soon as possible to avoid the risk of the RAS failing to operate for a future event. The drafting team declines to make the suggested change.

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Answer Comment:

The roles and relationships between the RAS-entity and the RAS-owners could be made clearer throughout the standard. Overall, FMPA supports the drafting team's approach, but there have been several comments submitted that should be considered before the standard is approved and would like to see outreach done *before* the next posting of the standard for comment and ballot.

Response: Thank you for your comments.

The drafting team consolidated the terms RAS-owner and RAS-entity. The term RAS-entity is now defined as the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Answer Comment:	(1) Requirement R9 requires the RC to update its RAS database annually. However, we believe the requirement should be rewritten to require the RC to develop and implement a process to conduct a review of its database and at what frequency. If a RAS-owner has not made any changes to functionality and system conditions and operating configurations are as expected, we feel this requirement is more of an administrative burden falling under Paragraph 81 Data Collection criteria. (2) We question how a RC is expected to maintain a dated revision history as evidence for Requirement R9 when the context of this requirement is to update a database. We believe the requirement is more of an administrative burden falling under Paragraph 81 Data Collection criteria, and the requirement should be rewritten to require the RC to develop and implement a process to conduct a review of its database and at what frequency. (3) We believe the evidence retention of this standard should identify retention periods for applicable entities and not limit retention just for TOs, GOs, and DPs. (4) The VSLs for Requirements R1 and R3 currently have only a Severe VSL identified. We believe the VSL criteria for these requirements could be written on a sliding time scale based on the projected installation or retirement dates of a RAS. (5) We believe the VSL criteria listed with many requirements is too condensed. We recommend incrementing the criteria for Requirement

R4 by quarters instead of by months. Moreover, we recommend incrementing the criteria for Requirement R5 by months rather than by every ten days. We also recommend incrementing the criteria for Requirements R8 and R9 by quarters rather every thirty days.

(6) We have concerns that the SDT has introduced a new measure of time, the “full-calendar-month.” This measure will cause confusion with implementation and during audits. Moreover, there is inconsistent uses of this time measure within the standard. The SDT uses 60-full-calendar-months in R4, but does not use the same measurement in R5 for 120-calendar days and R8 for six-calendar years. Should R5 be four-full-calendar-months and R8 be six-full-calendar-years? The rationale for “full-calendar months” is only specified within the RSAW of this Standard. We feel the SDT should remove the measure of “full-calendar months” and replace it with “calendar months” to be consistent with the other NERC standards.

(7) We thank you for this opportunity to comment on this standard.

Response: Thank you for your comments.

The drafting disagrees that updating a RAS database is an administrative requirement because the database serves as a reliability resource in that the RC can provide other entities high-level information from the database on existing RAS that could potentially impact the operational and/or planning activities of those entities. Readily available software tools allow easy and automatic application of revision dates to documents when updating database documents. Requirement R9 mandates an update frequency of at least every 12 full calendar months.

The drafting team revised the Compliance section of the standard to address this.

The drafting team does not agree that the VSL criteria for Requirements R1 and R3 should be written on a sliding time scale based on the projected installation or retirement dates of a RAS. Projected installation dates are not relevant to the reliability issues. The relevant issue, for both requirements, is to complete a review of the RAS prior to placing a new or functionally modified RAS in-service.

The drafting team declines to make the suggested change to the VSLs.

The drafting team notes that, e.g. PRC-026-1 also uses “full calendar months” terminology. The drafting team declines to make the suggested change.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Comment:	BPA believes R5’s reporting to the RC of the correct operation of a RAS is unduly onerous without providing value. BPA analyzes all RAS operations. If we see a scheme that operates too frequently (this is very subjective), we evaluate that scheme to see if there is something that can be done to minimize the number of operations. BPA proposes this be deleted from the requirement.

Response: Thank you for your comment.

The drafting team has modified Requirement R5 to only require reporting of the results of RAS operational analyses when there was an incorrect operation or failure to operate; correct operations do not need to be reported.

End of report