NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project 2010-05.1 Protection System (Misoperations)

The Project 2010-05.1 standard drafting team ("SDT" or "drafting team") thanks all commenters who submitted comments on the draft 5 of PRC-004-3 Reliability Standard. This draft Reliability Standard was posted for a 45-day public comment period from June 20, 2014 through July 9, 2014. Stakeholders were asked to provide feedback on the draft Reliability Standard and associated documents through a special electronic comment form. There were 47 sets of comments, including comments from approximately 136 different people from approximately 101 companies representing all 10 industry segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the NERC Standard's 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, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net . In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary of Changes

The drafting team determined certain non-substantive changes should be made in response to comments. The summary below provides an overview of the clarifications made to the draft PRC-004-3 Reliability Standard.

Definitions

The second sentence of the definition of "Composite Protection System" was clarified by changing the wording from an "inclusionary" to an "exclusionary" statement.

> "The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded."

The drafting team contends that this change is non-substantive because it is a clarifying rewording of the intent of the definition that was requested by commenters. The phrase for backup protection provided "to a remote Protection System" - "is included" is better described "by a different Element's Protection System" - "is excluded". Backup protection that is a part of the Protection System under study is "included." however, it is not intended that the "backup protection provided by a different

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

Element’s Protection System(s) to be” included. If this were the case, by definition, there would be very few identified Misoperations.

Requirements

Requirement R1

Requirement R1 was clarified based on comments. The drafting team moved the clause “under the following circumstances” (referring to Parts 1.1, 1.2, and 1.3) and added the clause with the clarifying reference to the Parts “under the circumstances in Parts 1.1 through 1.3” before the “shall” statement. The reason for moving the clause is based on comments noting that with the placement at the end of the requirement grammatically modified “Misoperation” and not the “BES interrupting device.” The drafting team agreed that moving the text would grammatically modify “BES interrupting device” without changing the meaning of the Requirement.

Requirement R1, Part 1.3 was clarified based on a comment revealing an unintentional omission in the circumstances in which an entity is required to review a BES interrupting device operation. The Requirement has three conditions for which the applicable entities must initiate a review of its Protection System to identify whether its Protection System component(s) caused a Misoperation. Part 1.1 has two conditions:

1. A BES interrupting device operation caused by a Protection System; or
2. A BES interrupting device operation caused by “manual intervention” in response to a Protection System failure to operate.

The comment revealed that in Part 1.3 that there was no circumstance for “manual intervention” that is included in Part 1.1. This unintentionally means that all three Parts (i.e., 1.1-1.3) could not be properly satisfied for the “manual intervention” circumstance (“was true”) in Part 1.1. Because of this, an applicable entity could reason that the “manual intervention” circumstance was not caused by an actual Protection System component per se. Since the BES interrupting device operation did not satisfy all the circumstances (“were true”) of the three Parts, the entity could reasonably justify that the operation does not need to be reviewed because Part 1.3 would not be true. The drafting team did not intend for Part 1.3 to create this circumstance. The drafting team agreed that this circumstance omission technically created an unintended condition in Requirement R1 where it is obvious that Part 1.3 should have included the “manual intervention” circumstance. Therefore, the drafting team inserted the phrase “or was caused by manual intervention in response to its Protection System failure to operate” to accurately account for the “manual intervention” condition specified in Requirement R1, Part 1.1 to make the intention clear to industry.

Requirement R2

Requirement R2, Part 2.1 received the same clarification to include “manual intervention” as Requirement R1, Part 1.3 based on comments. The intention is to notify other Protection System owners when either the BES interrupting device operation is caused by a Composite Protection System or "by manual intervention in response to a Protection System failure to operate."

Additionally, the drafting team inserted the term "BES" in Requirement R2, Part 2.2 before "Element" to clarify that backup protection was provided for a condition on another entity's "BES Element" and not on another entity's non-BES Element. This is consistent with the objectives listed in Section 5, Background of the draft PRC-004-3 Reliability Standard.

Requirement R3

No changes were made to Requirement R3.

Requirement R4

Requirement R4 was clarified by adding a parenthetical "(s)" to the second occurrence of "cause" for consistency with a previous occurrence in the Requirement.

Requirements R5 and R6

No changes were made to Requirements R5 and R6.

Measures M1 through M6

No changes were made to Measures M1 through M6.

Compliance

The clause "a minimum of" was added to the paragraphs pertaining to Requirements R1 through R6 to clarify that the evidence retention periods stated in the Compliance section are minimum retention periods. The drafting team made another clarification based on a comment about how the evidence retention period is applied to Requirements R1, R2, R3, and R4. To clarify that the minimum retention period applies to each Requirement, the drafting team added the clause "following the completion of each Requirement." Last, the drafting team clarified that evidence from R1 through R4 must be retained with the Corrective Action Plan.

Violation Risk Factors and Violation Severity Levels

There were no changes to Violation Risk Factors. The drafting team deleted "or not" from each of the Requirement R1 Violation Severity Levels. Requirement R1 does not mandate that an entity make a determination of whether "or not" an operation is a Misoperation. The reliability activity in Requirement R1 is to "identify whether its Protection System component(s) caused a Misoperation." The VSL could be construed as an expansion of the standard; therefore, the drafting team deleted "or not" based on a comment.

Guidelines and Technical Basis

The drafting team made grammatical corrections to text in the Rationale boxes associated with several Requirements. Rationale boxes will be moved to the end of the Guidelines upon adoption. The drafting team added a number of examples requested throughout comments. Also, the drafting team reconsidered the lowercase use of the term "fault" throughout the Guidelines and Technical Basis. The team changed a number of instances back to the *Glossary of Terms Used in NERC Reliability Standards* capitalized term "Fault" for increased clarity. The use of the term throughout the Guidelines and Technical Basis does not change any meanings and is only intended to provide the reader a more specific understanding of the guidance. Some instances were not changed because they are lowercase (e.g., use of "fault" in the current definition of "Misoperation").

Due to continued questions about the time periods in each of the Requirements, the drafting team consolidated text about time periods into its own section, "Requirement Time Periods." This section explains what other sections already addressed in one concise location for all Requirements. Last, minor corrections were made to the flowchart text to more closely align with the text in the Requirements based on a comment.

Implementation Plan

The drafting team corrected the Implementation Plan to align the definition of "Misoperation," category 2 and Applicability section concerning Facilities with the draft PRC-004-3 Reliability Standard. These revisions occurred in the previous posting and were not aligned with the text presented in the draft 5 of the PRC-004-3 Reliability Standard.

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Québec TransÉnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Matt Goldberg	ISO - New England	NPCC	2
9.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

12.	Helen Lainis	Independent Electricity System Operator	NPCC	2
13.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Silvia Parada Mitchell	Next Era Energy, LLC	NPCC	5
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si Truc Phan	Hydro-Québec TransÉnergie	NPCC	1
19.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
20.	Wayne Sipperly	New York Power Authority	NPCC	5
21.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
22.	Peter Yost	Consolidated Edison Co, of New York, Inc.	NPCC	3
23.	Brian Robinson	Utility Services	NPCC	8

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Tom McElhinney	JEA	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson		FRCC	1
2.	Garry Baker		FRCC	3
3.	John Babik		FRCC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Janet Smith	Arizona Public Service Company	X		X		X	X				

N/A

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

8. Ken Goldsmith	Alliant Energy	MRO	4
9. Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10. Marie Knox	MISO	MRO	2
11. Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12. Randi Nyholm	Minnesota Power	MRO	1, 5
13. Scott Nickels	Rochester Public Utilities	MRO	4
14. Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
15. Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
16. Tony Eddleman	Nebraska Public Power District	MRO	

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	Michael Jones	National Grid	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. Brian Shanahan	National Grid		3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	Mike Garton	Dominion	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Louis Slade	Dominion Resources Services, Inc.	RFC	5, 6
2. Randi Heise	Dominion Resources Services, Inc.	NPCC	5, 6
3. Connie Lowe	Dominion Resources Services, Inc.	SERC	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. DeWayne Scott		SERC	1
2. Ian Grant		SERC	3
3. David Thompson		SERC	5
4. Marjorie Parsons		SERC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	Colby Bellville	Duke Energy	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Doug Hils	Duke Energy	RFC	1
2. Lee Schuster	Duke Energy	FRCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10

3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	RFC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	David Greene	SERC Protection and Controls Subcommittee										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charles Fink	Entergy		
2.	Paul Nauert	Ameren		
3.	Bridget Coffman	Santee Cooper		
4.	Steve Edwards	Dominion		
5.	Jerry Blackley	Duke Energy Progress		
6.	David Greene	SERC		

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10. Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
2.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
3.	Annette Bannon	PPL Generation, LLC	RFC	5
4.		PPL Susquehanna, LLC	RFC	5
5.		PPL Montana, LLC	WECC	5
6.	Elizabeth Davis, LLC	PPL EnergyPlus, LLC	MRO	6
7.			NPCC	6
8.			RFC	6
9.			SERC	6
10.			SPP	6
11.			WECC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11. Group	Wayne Johnson	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
			Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing										
N/A													
12.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brian Hobbs	Western Farmers Electric Cooperative	SPP	1, 5
2.	Lucia Beal	Southern Maryland Electric Cooperative	RFC	3
3.	Mark Ringhausen	Old Dominion Electric Cooperative	SERC	3, 4
4.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
5.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
6.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
7.	John Shaver	Southwest Transmission Cooperative	WECC	1
8.	Bob Solomon	Hoosier Energy	RFC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Carol Chinn	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utilty Service	FRCC	3
7.	Stanley Rzad	Keys Energy Services	FRCC	1
8.	Don Cuevas	Beaches Energy Services	FRCC	1
9.	Mark Schultz	City of Green Cove Springs	FRCC	3
10.	Richard Bachmeier	Gainesville Regional Utilties	FRCC	1
11.	Mike Blough	Kissimmee Utility Authority		5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Robert Rhodes	SPP Standards Review Group		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joe Border	Board of Public Utilities, City of McPherson	NA - Not Applicable	NA
2.	Paul Von Herstenberg	Westar Energy	SPP	1, 3, 5, 6
3.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
4.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
5.	Mike Kidwell	Empire District Electric	SPP	1, 3, 5
6.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
7.	Shannon Mickens	Southwest Power Pool	SPP	2
8.	Lynn Schroeder	Westar Energy	SPP	1, 3, 5, 6
9.	Steve Shipps	Westar Energy	SPP	1, 3, 5, 6
10.	Sean Simpson	Board of Public Utilities, City of McPherson	NA - Not Applicable	NA
11.	Sam Snedaker	American Electric Power	SPP	1, 3, 4, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dean Bender	System Control Engineering	WECC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Dianne Gordon	Operational Compliance	X		X		X					

N/A

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Individual	David Jendras	Ameren	X		X		X	X				
18.	Individual	Chris Scanlon	Exelon Companies	X		X		X	X				
19.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				
20.	Individual	David Thorne	Pepco Holdings Inc	X		X							
21.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
22.	Individual	Amy Casuscelli	Xcel Energy	X		X		X	X				
23.	Individual	Barbara Kedrowski	Wisconsin Electric Power Company			X	X	X					
24.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
25.	Individual	Michael Haff	Seminole Electric Cooperative, Inc.	X		X	X	X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
26.	Individual	Oliver Burke	Entergy Services, Inc.	X									
27.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
28.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
29.	Individual	Roger Dufresne	Hydro-Québec					X					
30.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
31.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
32.	Individual	Jonathan Meyer	Idaho Power	X									
33.	Individual	Chris Mattson	Tacoma Power	X		X	X	X	X				
34.	Individual	Leonard Kula	Independent Electricity System Operator		X								
35.	Individual	Gul Khan	Oncor Electric Delivery LLC	X									
36.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
37.	Individual	Mahmood Safi	Omaha Public Power District	X		X		X	X				
38.	Individual	Louis C. Guidry	Cleco	X		X		X	X				
39.	Individual	Karin Schweitzer	Texas Reliability Entity										X
40.	Individual	Bill Temple	Northeast Utilities	X									
41.	Individual	John Brockhan	CenterPoint Energy	X									
42.	Individual	Don Cuevas	Beaches Energy Services	X									
43.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					
44.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
45.	Individual	Venona Greaff	Occidental Chemical Corporation							X			
46.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
47.	Individual	Michelle Clements	Wolverine Power Supply Cooperative, Inc.	X									

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The drafting team appreciates the entities below supporting the comments of others. Having single sets of comments with documented support greatly improves the efficiency of the drafting team in responding to comments. This format also ensures the drafting team has a clearer picture of the number of stakeholders supporting the same concerns or suggestions as the case may be.

Organization	Agree	Supporting Comments of "Entity Name"
Ameren	Agree	Ameren supports and adopts by reference the SERC PCS comments.
Beaches Energy Services	Agree	FMPA - Florida Municipal Power Agency
Occidental Chemical Corporation	Agree	Ingleside Cogeneration LP

1. **Based on stakeholder input, the drafting team revised the proposed definition of "Misoperation." Concerning the two categories of "Slow Trip." The drafting team also clarified the proposed definition of "Composite Protection System." Do you agree the revisions provided clarity? If not, please provide specific suggestions for improvement**

Summary Consideration: The numerical values are approximate and are intended to provide a gauge of the concerns raised by industry stakeholders. The number of comments noted is analogous to the number of entities (e.g., five comments means five entities provided a comment). More than 60 percent of individual stakeholders that commented in support of the drafting team's revised the proposed definition of "Misoperation," the two categories of "Slow Trip," and clarifications to the proposed definition of "Composite Protection System." There were 12 comments by 49 individuals that were not supportive of the revisions and there were 29 entities represented by 80 individuals that did not comment and only provided a "yes" response to the question in support of the drafting team's revisions.

There was one common issue raised in this section that resulted in a clarifying revision to the proposed definition of "Composite Protection System." Six comments by 34 individuals requested the drafting team to clarify the intent of the definition of "Composite Protection System" to eliminate the confusion of whether "remote" was local or away from the initiating Protection System. To clarify, the drafting team changed the last sentence from an "inclusionary" statement to an "exclusionary" statement. The phrase "[b]ackup protection provided to a remote Protection System is included" was clarified to "[b]ackup protection provided by a different Element's Protection System(s) is excluded."

There were three common issues that were raised by commenters that did not result in revisions. Three comments by 18 individuals requested changes to the definitions of "Composite Protection System" and "Misoperation." Another three comments by individuals noted a lack of clarity on the differences in either the categories of the definition of "Misoperation," the cited examples in the Guidelines, and/or the case where backup protection was provided for a failed Protection System of another owner. Two comments note that the definition of "Composite Protection System" is unnecessary and should not include, for example, redundant systems because in their opinion any failure in the Protection System should be identified as a Misoperation. The drafting team concluded that the suggested changes did not provide additional clarity.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	In the Composite Protection System definition “Backup protection provided to a remote Protection System is included.” is not clear because it directs the focus from the local protected Element to a remote protection system. Suggest revising this sentence to read “Backup protection provided by a remote protection system by design is included.” **Response:** The drafting team clarified the intent of the definition of “Composite Protection System” to eliminate the confusion of whether “remote” was local or away from the initiating Protection System. The phrase “a remote Protection System” was clarified to “a different Element’s Protection System.” Change made.
National Grid	No	Definitions for “Failure to Trip - During Fault” and “Failure to Trip - Other Than Fault” state that “The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct”. However, requirement R1 asks to identify if “Protection System component(s) caused a Misoperation”. These statements seem to contradict each other. **Response:** The drafting team asserts that every Protection System Misoperation will include the failure of a component to act properly for an identified Misoperation. If the Composite Protection System operates as intended, it is not a Misoperation. No change made. Definition for “Unnecessary Trip - Other Than Fault” provides examples for what it is not. It should also provide examples for what it is, similarly with other definitions. **Response:** The current draft includes what “is a Misoperation” (Examples 6a-6d) and what “is not a Misoperation” (Example 6e). No change made.

Organization	Yes or No	Question 1 Comment
PPL NERC Registered Affiliates	No	These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. It is helpful that the Definitions section on p.3 of the standard now says that a Slow Trip classification applies only if the Protection System of another Element was made to operate, but the term “slower than required” should be revised for clarity to read, “slower than the setting specified in the test/calibration instructions.” That is, a Slow Trip should be declared only if the timer is found to be mis-adjusted. Otherwise there’s no way of knowing whether the device at fault was slow or simply failed to function. Uncertainty on this subject is increased by Example 4 on p.25 having been left in its previous (draft 3) wording, “A failure of a generator's Composite Protection System to operate as quickly as intended for an overexcitation condition is a Misoperation.” This puts us back in the situation of having to decide if a relay acted in, say, ten cycles when five cycles was intended. Having to make such determinations ranges from being unduly burdensome to (for electromechanical relays) impossible, and was the principal reason for our having voted against draft 3 of the standard. It would be better still to state that Slow Trips apply only for TOs, because the issues of concern for this category of Misoperation (e.g. system instability, sequence of tripping) do not apply for generation plants. The description on p.25 of the standard of, “...owner(s) reviewing each Protection System operation,” to determine whether or not, “the speed and

Organization	Yes or No	Question 1 Comment
		outcome...met their objective," is not typical or appropriate for GOs, and they should not be required to add monitoring systems and design-level personnel to perform a no-value-added function. **Response:** The modifications to the category of "Slow Trip" were previously made to simplify the identification and improve the measurability. The identification is based on the reliability impact. It is appropriate to include Generator Owners in the standard's Applicability. No change made.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	The composite protection definition involving backup to remote protection does not completely make sense when coupled with the "slow trip" definition. The "total compliment" description in the Composite Protection System definition indicates that remote backup protection is included in the "total compliment". If the remote backup protection operates instead of the local, primary protection for an element, the "total compliment" collectively functioned to protect the element. Calling this situation a "misoperation of the Composite Protection System" is contradictory to stating that the total compliment collectively functioned as intended. Also, how does this make sense for the protection systems at generating facilities? What does 'backup protection provided by a remote protection system' mean for generating facilities? **Response:** The definition of "Composite Protection System," has been clarified to address the intent of backup protection. Clarification made. The slow trip definitions are still confusing. Are there multiple Composite Protection Systems that need to be considered when determining if a trip is a slow trip?

Organization	Yes or No	Question 1 Comment
		The "its operating time" references are indefinite in the definition. Consider making the slow trip definition either one of the following or a combination of the following OR statements: "a composite protection system operation that is slower than required or slower than designed or slower than desired or slower than the intended design". **Response:** The modifications to the category of "Slow Trip" were previously made to simplify the identification and improve the measurability. The identification is based on the reliability impact. No change made. There is a fundamental flaw in the definition of misoperation. A misoperation is recognizable any time any part of a protection system design fails to operate as intended by the design, regardless of the existence of a redundant, remote, or back up protection scheme. The fact that something did not operate properly should indicate that a misoperation has occurred. The addition of the adjective "reportable" simply classifies the types of misoperations that are to be reported. The comment above does not address a requirement governing the actual reporting. **Response:** The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This new definition has been introduced in this draft PRC-004-3 Reliability Standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation. No change made.

Organization	Yes or No	Question 1 Comment
Operational Compliance	No	A. The Application Guidelines provide some clarity on the difference between "Slow Trip - During Fault" and "Unnnecessary Trip - During Fault". However, these definitions may still not be entirely clear. **Response:** The drafting team asserts that the Guidelines and Technical Basis is the appropriate place for clarification rather than the definition of "Misoperation." No change made. B. Quoting Requirement R1...p.31 of Application Guidelines "When Elements are isolated from the BES and undergoing maintenance.....not subject to the standard....provided they do not result in the operation of...part of the BES." This statement and Example 6e (#6 of Misoperation definition), p.28 (at first glance anyways) may be at odds. **Response:** The text referenced on page 31 has been removed because maintenance cannot change the applicability of the standard. Example 6e is not a Misoperation of an in-service Element because of the maintenance exclusion; however, the owner of the BES interrupting device that operates will review the operation when the operation meets the circumstances in Requirement R1, Parts 1.1 through 1.3. Clarification made.
Wisconsin Electric Power Company	No	The 2nd sentence in the definition of Composite Protection System is "Backup protection provided to a remote Protection System is included." The meaning and intention of this phrase is not readily understood. We suggest that the phrase from previous Draft 4: "Backup protection provided by a remote Protection System is excluded", is clearer and should be re-instated. **Response:** The definition of "Composite Protection System," has been clarified to address the intent of backup protection by providing an

Organization	Yes or No	Question 1 Comment
		"exclusionary" condition rather than an "inclusionary" condition. Clarification made.
Public Service Enterprise Group	No	We agree with the Slow Trip changes. However, the revised definition of Composite Protection System caused much discussion. In the end, we would accept it provided that "a remote" in the second sentence is changed to "another." With this change, the second sentence would read "Backup protection provided to another Protection System is included." The backup Protection System need not be "remote" physically; it could be located in the same substation. The phrase "a remote Protection System" would require that the backup Protection System be at a different physical location, which may not be the case as we have just described. **Response:** The drafting team clarified the intent of the definition of "Composite Protection System" to eliminate the confusion of whether "remote" was local or away from the initiating Protection System. The phrase "a remote Protection System" was clarified to "a different Element's Protection System." Clarification made.
Independent Electricity System Operator	No	We generally agree with the changes to the proposed definition of Misoperation, but do not agree with the proposed addition of the term Composite Protection System. In our previous comments, we expressed our disagreement with the need to create a defined term "Composite Protection System". By definition, a Protection System is already a composite system whose components need to function collectively to protect an Element. The proposed term is therefore redundant. In the comment report, the SDT's response indicates that the reason for proposing the newly defined term, "Composite Protection

Organization	Yes or No	Question 1 Comment
		System," is found in the Application Guidelines under the heading "Definitions.", and therefore no change was made. In the Application Guideline, the rationale provided for introducing this new term is that: [The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.]We find this rationale insufficient to justify the introduction of the new term since by having the defined term "Misoperation" which covers any failure a Protection System to operate as intended for protection purposes would suffice to include the effect of multiple levels of protection (e.g. redundant systems). In other words, if a Protection System failed to operate as intended or operated unnecessarily, then regardless of the level of protection and which component caused the Protection System to operate, the action/inaction of the Protection System - Composite or otherwise, would constitute a Misoperation. We therefore continue to disagree with the proposed addition of this new term, and suggest that it be removed. **Response:** Not all entities consider a Protection System to include all associated components to protect an Element. The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This new definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation. Also, the new definition supports consistent

Organization	Yes or No	Question 1 Comment
		reporting of Misoperations under the Section 1600 data request because all entities, under the new definition, will be evaluating its Composite Protection Systems in the same manner. No change made.
Southern California Edison Company	No	SCE disagrees with the explanation of and rationale for the "Composite Protection System" for the following reasons: 1. If an interrupting device is tripped due to misoperation of another device not owned by the owner of the interrupting device, then the owner of the interrupting device will be unaware of this issue until the formal notification of the event to all the owners of the composite protection system is made. One of the reasons for the misoperation of the other device could be a failure to trip. **Response:** The drafting team contends that this concern is addressed by Requirement R2. The new definition of "Composite Protection System," has been clarified to address the intent of backup protection. Clarification made. 2. In the case above, the owner of the interrupting device would not be able to validate Requirement 1.3: "The BES interrupting device owner identified that its Protection System Component caused the BES interrupting device(s) operation." Therefore the owner would not be able to and may not be required to notify other entities owning the composite protection system. The root cause would either not be analyzed or the analysis would be delayed. **Response:** Requirement R1 is for the BES interrupting device owner to initiate the review for identifying any Misoperations caused by its components. Requirement R2 addresses the circumstances in which the initiating BES interrupting device owner in Requirement R1 must make

Organization	Yes or No	Question 1 Comment
		notification to other owners. The notified Protection System component owner(s) in R3 must review its portion of the Composite Protection System for any Misoperation. No change made.
Northeast Utilities	No	The part of the Composite Protection System definition "Backup protection provided to a remote protection is included" is not clear because it switches focus from the local protected element to a remote protection system. We suggest revising this part to say "Backup protection of the element provided by a remote protection by design is included." **Response:** The drafting team clarified the intent of the definition of "Composite Protection System" to eliminate the confusion of whether "remote" was local or away from the initiating Protection System. The phrase "a remote Protection System" was clarified to "a different Element's Protection System." Clarification made.
CenterPoint Energy	No	CenterPoint Energy recommends adding wording to the definition to address the direct interrelationships between Misoperation categories, especially the "Slow Trip - During Fault" and the "Unnecessary Trip - During Fault" categories. For these two categories, an operation of an un-faulted Element's Composite Protection System occurs. This interrelationship is detailed in the Application Guidelines which states the following for the "Slow Trip - During Fault" category: "In analyzing the Protection System for Misoperation, the entity must also consider the "Unnecessary Trip - During Fault" category to determine if an "unnecessary trip" applies to the Protection System operation of an Element other than the faulted Element. If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip - During Fault" category of Misoperation at the local terminal." In addition, the Application Guidelines states the following for the Unnecessary Trip - During

Organization	Yes or No	Question 1 Comment
		Fault: “If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip - During Fault” category of Misoperation at the remote terminal.” CenterPoint Energy suggests adding clarifying wording at the end of the “Slow Trip - During Fault” and the “Unnecessary Trip - During Fault” categories: 3. Slow Trip - During Fault - A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System, providing it is not determined to be an Unnecessary Trip - During Fault. 5. Unnecessary Trip - During Fault - An unnecessary Composite Protection System operation for a Fault condition on another Element, providing it is not determined to be a Slow Trip - During Fault. **Response:** The drafting team asserts that the Guidelines and Technical Basis is the appropriate place for additional explanation rather than within the definition of “Misoperation.” No change made.
Flathead Electric Cooperative, Inc.	No	Generally do not like the phrase "composite", would prefer that Protection System just have a solid definition. I appreciate that is the dilemma here and my specific suggestion be to delete the word composite throughout. **Response:** The drafting team contends that modifying the Protection System definition in the *Glossary of Terms Used in NERC Reliability Standards* impacts all Reliability Standards using the term. No change made.
JEA	Yes	

Organization	Yes or No	Question 1 Comment
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
Duke Energy	Yes	
SERC Protection and Controls Subcommittee	Yes	
ACES Standards Collaborators	Yes	We agree with the changes. **Response:** Thank you for your comment.
Florida Municipal Power Agency	Yes	FMPA's primary concern with the previous version of this definition centered around the ability to accurately classify the events and show evidence as appropriate. FMPA agrees the revised versions of "Slow Trip - During Fault" and "Slow Trip - Other than Fault" are more specific and thus easier to consistently apply. However, we do not believe the revised versions are going to result in events being classified the way the SDT desires. We are voting yes for this item because our primary concern is addressed. The SDT should reconsider these revisions, though, in light of the following - the revised versions have nothing to do with the designed, set, or normal operating time as specified by the relay manufacturer/settings. We believe the intent of these two categorizations is to identify relay misoperations for which a relay, interrupting device, or relay setting which was intended to operate at a particular speed, instead operated at a slower speed / in a

Organization	Yes or No	Question 1 Comment
		longer time. Just because a relay from a different Element's Composite Protection System operates does not necessarily mean this event was undesired, unnecessary, or unintended. As stated in our last comments we refer back to the core issue that the protection system performance should be measured against a company's relay setting philosophy. We also note that the Application Guide still refers to this event in "Example 3" as "A failure of a line's Composite Protection System to operate as quickly as intended...". **Response:** The modifications to the category of "Slow Trip" were previously made to simplify the identification and improve the measurability. The identification is based on the reliability impact. Example 3 in the Guidelines and Technical Basis have been clarified to remove the "quickly" wording. The drafting team contends that design philosophies inherently include the principles of dependability and security. Each entity using its particular design philosophy would lead to less consistent classification of Misoperations. No change made. The application guide also still includes language regarding "slower than previously identified as being necessary to prevent voltage or dynamic instability". **Response:** The Guidelines and Technical Basis have been updated to remove this reference. Correction made.
SPP Standards Review Group	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 1 Comment
Exelon Companies	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc	Yes	The most recent draft of the proposed standard added a definition for a composite protection system which satisfies our previous concerns. **Response:** Thank you for your comment.
American Electric Power	Yes	
Xcel Energy	Yes	
Entergy Services, Inc.	Yes	
American Transmission Company	Yes	
Kansas City Power & Light	Yes	
Hydro-Québec	Yes	
Nebraska Public Power District	Yes	
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration (“ICLP”) agrees that the drafting team has made a change for the better in the definition of “Misoperation”. The prior version would perhaps lead to more technically-accurate identifications of slow-trip incidents, but made too many assumptions around our capability as a GO to conduct a performance evaluation of the Composite Protection System. We simply do not have the tools or training to determine if high-speed

Organization	Yes or No	Question 1 Comment
		performance is necessary to prevent voltage or dynamic instability. In fact, we may not be aware that a slow trip took place if a secondary or back-up Protection System acts in a manner that masks the condition. We believe that improper operation of a nearby Protection System may be an indication that a slow trip occurred. From that point on, an investigation can ensue that has a chance of success - as our investigative capabilities are designed to address such events. In addition, the bright-line definition leaves no room for a violation assessment based upon a CEA's interpretation that the GO should have deployed sophisticated recorders (DME) or situational analysis tools to prepare for a Misoperation of the type. **Response:** Thank you for your comment.
Idaho Power	Yes	
Oncor Electric Delivery LLC	Yes	
Omaha Public Power District	Yes	
Cleco	Yes	
Texas Reliability Entity	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Electric Reliability Council of Texas, Inc.	Yes	

Organization	Yes or No	Question 1 Comment
Wolverine Power Supply Cooperative, Inc.	Yes	

2. Based on stakeholder input, the drafting team revised Requirement R2 to clarify responsibilities when local protection is responsible for the interrupting device operation and when backup protection is responsible. This also addresses the notifications that must occur to eliminate a gap in the previous draft. The gap was a condition where an entity's BES interrupting device did not operate because of a failed Protection System; therefore, would not have been applicable to the standard. Do you agree that the gap has been eliminated with the change to Requirement R2? If not, please provide specific suggestions for improvement.

Summary Consideration: The numerical values are approximate and are intended to provide a gauge of the concerns raised by industry stakeholders. The number of comments noted is analogous to the number of entities (e.g., five comments means five entities provided a comment). More than 62 percent of individual stakeholders agreed with the approach used by the drafting team in Requirement R2 to clarify responsibilities when local protection is responsible for the interrupting device operation and when backup protection is responsible. This also addresses the notifications that must occur to eliminate a gap in the previous draft 5.

There were two common comment themes that required a clarification in the standard. First, a single comment by 23 individuals raised concern that the drafting team failed to make it obvious that an entity should also have to notify other owner(s) of Protection Systems under the same circumstances in Requirement R1 for a BES interrupting device operation by manual intervention in response to a Protection System failure. The drafting team agreed with the lack of clarity and inserted the appropriate phrase to highlight that this circumstance is intended to be covered by Requirement R2. Second, two comments by individuals disagreed with the way Requirement R2, Part 2.2 was constructed when compared with the definition of "Composite Protection System." The drafting team did not make a change to Part 2.2 based on the comment, but provided additional explanation in the response how the clarification to the definition of "Composite Protection System" should address the concern.

There were six varying comment themes that did not require the drafting team to clarify the standard. Of those, two comments by nine individuals believed that requirements for providing notifications overly complicate the standard. The drafting team contends that requiring notifications is important to ensuring all Protection System owners become aware of when they need to review their Protection Systems, and when notified, that they have a responsibility to perform the necessary requirements. A single comment expressed concerned about the entity that provided remote backup protection having to track operations. The drafting team noted that a BES interrupting device operation meeting the circumstances in Requirement R1 dictate that a review of the operation be performed. Requirement R2, Part 2.2 requires that entity to notify the other owner(s) for which backup protection was provided. Two comments by 12 individuals were concerned that 120 calendar days is too long of a period and would not promote effective and efficient resolution of the problem. The drafting team contends that most Protection System reviews would occur soon after a

BES interrupting device operation. The 120 calendar days is a maximum time allowance and provides for seasonal variations in operations and work load.

The last three comments were provided by an individual commenter. One comment raised concern that Measure M2 limited an entity's ways to demonstrate coordination of evidence. The drafting team contended that Measure M2 specifically notes that evidence "may include, but is not limited to." A second comment disagreed that the BES interrupting device owner should be responsible for demonstrating compliance with the requirements in the proposed standard. The drafting team contends that the trip coil(s) of a BES interrupting device are, by definition, included in what is considered a Protection System. Last, one comment pointed out that the entity did not see how the gap regarding a case where an interrupting device did not operate has been addressed. The drafting team is confident that a BES interrupting device will operate, somewhere in the system to clear the abnormal condition, thus the entity that owns the BES interrupting device that clears the abnormal condition will notify the other owner(s).

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	The case where manual intervention is required to open a BES interrupting device, but the cause of the Misoperation is located on a Protection System component owned by another Transmission Owner is not addressed in R2. In R1 a special mention to manual intervention is included. Why isn't a process of notification included in R2 for manual intervention caused by Misoperation of another owner's protection system? **Response:** The drafting team intended in Requirement R2 that a BES interrupting device operation due to a Protection System operation or by manual intervention in response to a Protection System failure would be considered in whether or not notifications to other owners would be required. The drafting team added the appropriate clarification for "by manual intervention in response to a Protection System failure to operate." Clarification made.
Southern Company: Southern Company Services, Inc.;	No	There is a problem with R2.2. One entity does not necessarily know whether or not another entities' Element has an abnormal condition. This notification of other entities

Organization	Yes or No	Question 2 Comment
Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		for an explained operation of my interrupting device and my protection system should not be required. It is acknowledged that this was an attempt to eliminate the gap described above, but it is contrary to the Composite Protection System collectively functioning as intended to protect an element. **Response:** Requirement R2 provides the circumstances where the initiating entity either determines that the operation was not caused by its Composite Protection System components or the initiating entity is unable to rule out a Misoperation. The drafting team contends that the initiating entity will be in the position to determine its Protection System operated correctly. If not, Requirement R2 requires notification to other owners if the initiating entity is unable to rule out a Misoperation. No change made. Also, the drafting team clarified the intent of the definition of “Composite Protection System” to eliminate the confusion of whether “remote” was local or away from the initiating Protection System. The phrase “a remote Protection System” was clarified to “a different Element’s Protection System.” Clarification made.
ACES Standards Collaborators	No	(1) We continue to believe that this standard has been overly complicated by including administrative elements such as reporting information to third parties. The reporting does little to nothing to support reliability. The real value is in analyzing the Protection System operations and correcting any errors. Is there any indication that registered entities are not communicating to co-owners of the Composite Protection System that a potential misoperation occurred? If not, (and we have seen no such evidence) why does this administrative requirement that clearly meets multiple P81 criteria (administrative and reporting) rise to level of needing to be enforced with financial penalties? Barring such evidence, we simply do not see how we can support such a requirement. Clearly, the application guidelines spell out what is necessary. We recommend that the drafting team perform a study to determine if there is a true

Organization	Yes or No	Question 2 Comment
		reliability need for communicating with co-owners of Composite Protection Systems. If the drafting team cannot provide data or statistics indicating a gap in reliability, then we recommend striking the administrative tasks from the requirement. **Response:** Requirement R2 requires notification to other owners of the Composite Protection System who have a reliability role in identifying Misoperations, but were not accounted for within Requirement R1. Requirement R2, under the circumstances in Part 2.1 and Part 2.2 determine when the notification to other owners must occur. No change made. (2) The existing standard was fairly simple and coupled with the new definition of Misoperation largely addresses the scope of the SAR. All that is really is needed for this standard is a requirement to evaluate Protection System operations, identify if the Protection System operation was a misoperation and then to develop a Corrective Action Plan to prevent future misoperations. Six requirements create more complication than what is necessary. **Response:** The Requirements provide additional clarity over the current version two PRC-004-2.1a Reliability Standard that has three activities in a Requirement. This draft version three PRC-004-3 Reliability Standard has one reliability activity per Requirement and those Requirements provide the essential actions to ensure each and all entities are informed. No change made.
Seminole Electric Cooperative, Inc.	No	Requirements R1 and R2 place the burden on the owner of a BES interrupting device to initiating a review on the operation of the device. This responsibility should fall on the owner of the components of the Composite Protection System that initiated the BES interrupting device to operate. The owner of these components should be just as aware as the owner of the device regarding its operation. In addition, for those entities that are interconnected and who utilize the same BES interrupting device, those entities should have equal awareness of the BES interrupting device status.

Organization	Yes or No	Question 2 Comment
		Therefore, Seminole recommends that the SDT revise Requirements R1 and R2 to require the entity whose components of the Composite Protection System initiated the BES interrupting device to activate. **Response:** According to definition of Protection System which became effective April 1, 2013, the BES interrupting device owner owns a component of the Protection System, namely the trip coil(s) of that BES interrupting device (at a minimum). The BES interrupting device owner is in the best position to be aware of the operation and to initiate the identification of any Misoperation. In the case where the relays or other Protection System component(s) are owned by another entity, that owner may not know of the operation until it receives notification from the BES interrupting device owner. No change made.
Nebraska Public Power District	No	R2 2.2 states: "For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided." Perhaps it would be clearer to state: "For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's Element, notification of the operation shall be provided to the other Protection System owner(s) from the backup protection system owner(s) for which that backup protection was provided." **Response:** The drafting team disagrees that the suggestion provides additional clarity. No change made.

Organization	Yes or No	Question 2 Comment
		A concern with the gap fix is that the backup protection system owner will not be tracking this as a misoperation because the owner of the interrupting device is the one who had the misoperation yet the backup protection owner must store this notification as part of a misoperation on another entities system which creates an odd and risky compliance tracking situation. It would be unfortunate to get fined for not tracking this even though a misoperation did not occur on your system. This is a difficult situation to address. **Response:** Regardless of fixing the gap (i.e., R2, Part 2.2), the entity that experienced a BES interrupting device operation is required to review the operation according to the circumstances in Requirement R1. For example, if the operation was "correct" it would not be identified as a "Misoperation;" however, Requirement R2, Part 2.2 requires that the entity provide notification to the other Protection System owner(s) if the operation was a result of providing backup protection for a condition on another entity's Element. No change made. For a backup protection system owner who operates in back up for a fault on a non BES or non-registered entities system is the notification not required? **Response:** Requirement R2, Part 2.2 has been clarified that the "other entity's Element" is a "BES Element." The Guidelines and Technical Basis have been supplemented for this condition. Clarification made.
Idaho Power	No	Protection Systems regularly provide backup to the next Element. These backup features are not intended to operate under normal conditions and would not be included as part of an Element's Composite Protection System as we interpret it. The phrase "intended to operate" in 2.2 should be modified to account for operations of another Element's Composite Protection System that could operate as backup to the normal Composite Protection System for an extreme event.

Organization	Yes or No	Question 2 Comment
		Response: The drafting team clarified the definition of "Composite Protection System." Back up protection provided by a different Element's Protection System(s) is excluded. The intent of Requirement R2, Part 2.2 is for the condition where an entity provides backup protection for a different Element's Protection System, such as, the case of a failed protection system of another BES Element. Part 2.2 requires that the entity that provided the backup protection (i.e., a correct operation) is required to notify the other Protection System owners to close the reliability gap for a BES interrupting device that did not operate. A clarification was made to the definition of "Composite Protection System."
Southern California Edison Company	No	In the case where a non-performing protection system has caused a tripping device to operate, the non-tripping device could be ignored, resulting in the problem not being mitigated and eventually posing a greater risk to the composite protection system. Assuming that the owner of the system notifies the other entities owning the composite protection system, the time window of 120 days to notify would be too long in order to promote effective and efficient resolution of the problem. Notification should be within a week of the occurrence of event in order to allow the other impacted entities to review, analyze, and communicate with each other in order to perform a root cause analysis and determine a corrective action plan. **Response:** The drafting team concluded that most Protection System reviews would occur soon after a BES interrupting device operation. The 120 calendar days is a maximum time allowance and provides for seasonal variations in operations and work load. Also, requiring automatic notifications to other owners of the Composite Protection System would create an unnecessary compliance burden on entities (i.e., Requirement R3) if the initiating entity did not perform a cursory review of the Protection System operation first. No change made.

Organization	Yes or No	Question 2 Comment
		Requirement R2 provides the circumstances where the initiating entity either determines that the operation was not caused by its Composite Protection System components or the initiating entity is unable to rule out a Misoperation. No change made.
Tri-State Generation and Transmission Association, Inc.	No	Tri-State remains concerned with situations where individual components are jointly owned. The SDT's response "While a Protection System may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results" appears to require all entities to report the operation giving double jeopardy to each misoperation on jointly-owned Composite Protection System components, unless a contract speaks to the designated "Compliance Entity". Typically compliance contracts take some time to come to fruition. Is it the drafting team's intent that misoperations be reported by multiple entities in this situation until a contract is finalized? **Response:** The reporting of Misoperations is outside the scope of the draft PRC-004-3 Reliability Standard and is being addressed by the NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., "data request"). Absent an agreement, all owners of a Protection System will have a compliance responsibility. No change made.
Flathead Electric Cooperative, Inc.	No	The way the M2 is written is overly prescriptive and limiting on what might be acceptable way to show the coordination between entities. The measure seems to written like a requirements. Prefer the previous language.

Organization	Yes or No	Question 2 Comment
		Response: The drafting team notes the Measure is worded “may include, but is not limited to,” thus allowing other forms of evidence. The wording of the Measure follows NERC guidance. No change made.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
National Grid	Yes	
Dominion	Yes	
Duke Energy	Yes	
SERC Protection and Controls Subcommittee	Yes	
SPP Standards Review Group	Yes	Formatting in recent standards has tended toward using bullets in lieu of subparts. The drafting team is encouraged to follow this practice in Requirement R2. Note that there are bullets in Requirement R5. **Response:** The drafting team followed the NERC convention for numbering and bulleting. Numbered items mean “and” which requires all of the items to be considered or performed. Bullets mean “or” and generally mean one or more are required depending on the Requirement text. No change made.

Organization	Yes or No	Question 2 Comment
		Delete the 2nd 'when' in the 6th line (clean copy) of the Rationale Box for Requirement R2. **Response:** The drafting team removed the second occurrence of "when." Change made.
Bonneville Power Administration	Yes	
Operational Compliance	Yes	
Exelon Companies	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc	Yes	We are in agreement that this revision eliminates the identified gap. However, we are still not in agreement that the owner of the interrupting device be responsible for demonstrating compliance with the requirements in the proposed standard, as has been previously stated. This is of particular interest at interface terminals with generator owners. **Response:** The drafting team thanks you for your comment. The drafting team contends that the BES interrupting device owner is in the best position to be aware of the operation and to initiate the identification of any Misoperation. No change made.
American Electric Power	Yes	
Xcel Energy	Yes	

Organization	Yes or No	Question 2 Comment
Wisconsin Electric Power Company	Yes	
Public Service Enterprise Group	Yes	
Entergy Services, Inc.	Yes	
American Transmission Company	Yes	
Kansas City Power & Light	Yes	
Hydro-Québec	Yes	
Ingleside Cogeneration LP	Yes	ICLP agrees that there are situations where a relay owned by an external entity may trip a circuit breaker protecting an Element owned by another entity. The interrupting device and relay owners will need to coordinate their investigations in order to resolve the issue - and R2 now ensures that the process will be initiated. **Response:** The drafting team thanks you for your comment.
Tacoma Power	Yes	
Independent Electricity System Operator	Yes	
Oncor Electric Delivery LLC	Yes	

Organization	Yes or No	Question 2 Comment
Omaha Public Power District	Yes	
Cleco	Yes	
Northeast Utilities	Yes	
Electric Reliability Council of Texas, Inc.	Yes	
Wolverine Power Supply Cooperative, Inc.	Yes	
Florida Municipal Power Agency		1. FMPA does not feel our previous comment regarding notification to affected entities was properly understood. This comment was offered to R2 in the previous round of comments. We understand the way the document is intended to flow, but our main concern is the relay event records are preserved by all entities indefinitely - for many Utilities a special trip must be made to the substation to download the event records. What prevents the Owner of a BES interrupting device that operated from taking the full 120 days to conduct their review without saying anything to the other affected owners, only to find upon request of further evaluation that those entities no longer have the relay event records necessary for the evaluation? At minimum the entity Owning the BES interrupting device should advise the other affected Protection System owners that the investigation is under way at the earliest time they determine those entities are affected, to allow the entities to be prepared with data should they be notified in accord with R2. **Response:** The drafting team concluded that most Protection System reviews would occur soon after a BES interrupting device operation. The 120 calendar days is a maximum time allowance and provides for seasonal variations in operations and work

Organization	Yes or No	Question 2 Comment
		load. Also, requiring automatic notifications to other owners of the Composite Protection System would create an unnecessary compliance burden on entities (i.e., Requirement R3) if the initiating entity did not perform a cursory review of the Protection System operation first. No change made. FMPA does not see how the gap regarding a case where an interrupting device did not operate has been addressed. Reading R1 and R2 again, it still appears that all triggers for activity are based on interrupting device operation, and we see no mention of a case where an interrupting device did not operate. While we can see that requiring actions in the standard based on relay targets, for example, would be challenging to enforce, we would have expected at least a statement, something to the effect of “Or if the entity otherwise becomes aware that a Composite Protection System it owns operated without an associated interrupting device action”. **Response:** The drafting team is confident that a BES interrupting device will operate, somewhere in the system to clear the abnormal condition. The draft PRC-004-3 Reliability Standard is initiated on the operation of a BES interrupting device. Requirement R2 addresses this perceived gap for a device not operating because an entity that provided backup protection is required to notify the entity for which it provided backup protection. The other entity is then required under Requirement R3 to review its Protection System for Misoperation. No change made.
Texas Reliability Entity		No comments
CenterPoint Energy		CenterPoint Energy recommends deleting the proposed Requirement R2.2. Based upon the changes made to the Composite Protection System definition and the proposed wording of Requirement R2.1, CenterPoint Energy believes the proposed wording of Requirement R2.2 related to backup protection is unnecessary. The Composite Protection System definition now states that “Backup protection provided

Organization	Yes or No	Question 2 Comment
		to a remote Protection System is included." This, along with Requirement R2.1 stating "notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances" and Requirement R2.1.2 stating "The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation", provides for the notification intended by Requirement R2.2. **Response:** The drafting team clarified the definition of "Composite Protection System." Back up protection provided by a different Element's Protection System(s) is excluded. The intent of Requirement R2, Part 2.2 is for the condition where an entity provides backup protection for a different Element's Protection System, such as, the case of a failed protection system of another Element. Part 2.2 requires that the entity that provided the backup protection (i.e., a correct operation) is required to notify the other Protection System owners to close the reliability gap for a BES interrupting device that did not operate. A clarification was made to the definition of "Composite Protection System."

3. The drafting team modified the Application Guidelines to improve examples and clarify the team's intent on various topics. Do you agree the Application Guidelines provide sufficient examples and clarity? If not, please provide specific suggestions for improvement.

Summary Consideration: The numerical values are approximate and are intended to provide a gauge of the concerns raised by industry stakeholders. The number of comments noted is analogous to the number of entities (e.g., five comments means five entities provided a comment). More than 70 percent of individual stakeholders agreed that the Guidelines and Technical Basis was improved by the numerous examples and that it clarified the team's intent on various topics.

There were three themes in the comments that resulted in revisions to the standard's Guidelines. Five comments by 16 individuals requested additional examples in the Guidelines. Among the requests, examples included breaker failure, "Failure to Trip – During Fault," "Slow Trip – During Fault," "Slow Trip – Other Than Fault," "Unnecessary Trip – During Fault," and Requirements R1 and R2. The drafting team supplemented the Guidelines with most of the examples suggested by stakeholders. Four comments by 14 individuals suggested minor word clarifications, punctuation improvements, and grammar corrections needed in the Guidelines. The drafting team concurred with many of the suggestions and implemented the clarifications, improvements, and corrections. A single comment by 11 individuals noted minor issues with wording in the Guidelines that was not updated during previous revisions of the definitions. The drafting team addressed these issues.

The following five comments did not result in revisions or clarifications in the draft PRC-004-3 Reliability Standard or related documents. First, four comments by 21 individuals remained concerned with the "Slow Trip" category of the Misoperation definition. The drafting team noted that it may take a detailed investigation to distinguish between a "Slow Trip" and "Failure to Trip" category of Misoperation. However, making a distinction is not relevant to the Requirements because the entity is required to identify whether a Misoperation of its Protection System components occurred. Second, one comment by 11 individuals expressed concern that an entity does not have any flexibility in the timeframes of the Requirements for extenuating circumstances if the entity did not meet the timeframes due to an event such as a natural disaster. The drafting team responded that NERC and the Regional Entity do not have the authority to provide flexibility regarding the performance (i.e., "timeframes") of a Reliability Standard in unique extenuating circumstances. However, the Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances allow the Compliance Enforcement Authority this flexibility based on the entity's unique circumstances. Third, a single commenter believed that Bulk Electric System (BES) Elements or Protection System Misoperations that may affect the reliability of the Bulk Electric System (BES) should be first identified by the Planning Coordinator or Reliability Coordinator. The drafting team noted that the current version of the draft Reliability Standard (PRC-004-2.1a) applies to all BES Protection Systems; therefore, the Planning Coordinator or Reliability Coordinator do not need to identify specific BES Elements that affect reliability, only the owners of Protection Systems. Fourth, an individual commenter suggested adding a Requirement to require the BES interrupting device owner to share any information it has regarding the operation of the Composite Protection System. The drafting team finds such a requirement to be administrative and a compliance burden when information is already being communicated. Last, a single commenter questioned about how the timeframes relate between the Requirements. The drafting team appended a new section, “Requirement Time Periods” to the Guidelines to provide clarity regarding timeframes.

Organization	Yes or No	Question 3 Comment
PPL NERC Registered Affiliates	No	See our comments above for Example #4. The Application Guidelines should clarify Misoperation analysis scope and purpose differences between TOs (preserve stability and enforce orderly isolation of circuits on a still-live system) and GOs (trip the unit). **The following text was provided to the drafting team by the group’s submitter after the drafting team requested clarification to the above comment:** *The following response was developed by a PPL SME. Please contact me if you have additional questions.* *The issue has to do with our objections regarding slow trips. Previous versions of the standard could be interpreted as requiring us to identify the time delay associated with every relay action, to see if the device functioned as quickly as intended. We (and probably most GOs) don’t have equipment allowing such a determination. The SDT sought to address this concern by revising the definitions to state that a slow trip occurs only if another, backup relay was made to operate.* *Two shortcomings remain, however. One doesn’t know whether the primary device that didn’t get the job done was slow or it was utterly non-functional. The classification of a slow trip should then apply only if the timer was found to be mis-programmed.*

Organization	Yes or No	Question 3 Comment
		Response: Since the symptoms are similar, it may take a detailed investigation to distinguish between a "Slow Trip" and "Failure to Trip" category of Misoperation. However, this is not relevant to the Requirements. The entity is required to identify, within 120 days, whether a Misoperation occurred. The definition's wording change simplifies the identification process by allowing entities to use an operational evaluation to identify whether a Misoperation occurred. In the cited example, it should become clear during subsequent investigation whether a "Slow Trip" or "Failure to Trip" type Misoperation occurred. No change made. Secondly, the SDT forgot to revise the wording for Example 4 on p.25 of the Application Guidelines. It still talks about, "A failure of a generator's Composite Protection System to operate as quickly as intended," contradicting the revised definition. **Response:** Example 4 has been updated.
SPP Standards Review Group	No	We note that the drafting team included several additional examples in this version of the standard and we certainly appreciate that. We would however suggest that the following examples would provide further clarification: 1) an example which illustrates that a properly coordinated breaker failure operation does not equate to a slow-trip operation, **Response:** The drafting team has provided an example in the Guidelines and Technical Basis under "Composite Protection System – Breaker Failure Example" section, second bullet. Clarification made. 2) a backup protection example to provide clarity on how Requirement 2, Part 2.2 would be applied and

Organization	Yes or No	Question 3 Comment
		Response: The drafting team has provided Example 1e in the Guidelines and Technical Basis. Clarification made. 3) an example of a breaker failure Misoperation. **Response:** The drafting team has provided an example in the Guidelines and Technical Basis under "Composite Protection System – Breaker Failure Example" section, third bullet. Clarification made. We noted that the drafting team reverted to the non-capitalized 'fault' throughout most of the Application Guidelines. Yet in the listing of items that characterize a Misoperation on Page 23 (clean copy), the drafting team maintained the capitalization from the previous draft. Can the drafting team provided clarification on the proper use of the term? **Response:** The drafting team re-evaluated the general use of "fault" and the *Glossary of Terms Used in NERC Reliability Standards* definition of "Fault." The evaluation resulted in reverting certain occurrences that should refer to the glossary definition. Clarification made. In the 1st line under Unnecessary Trip - Other Than Fault on Page 26 (clean copy), delete the comma between 'to' and 'power'. **Response:** Punctuation correction made. Hyphenate 'out-of-service' in the paragraph following Example 7a on Page 27 (clean copy). **Response:** Punctuation correction made. Hyphenate 'high-side' in the 3rd line of Example 7b on Page 27 (clean copy). **Response:** Punctuation correction made.

Organization	Yes or No	Question 3 Comment
		Replace 'voltampere-reactive' with 'VAr' in the 3rd line of the paragraph under Non-Protective Functions on Page 27 (clean copy). **Response:** The usage of "static voltampere-reactive compensator" is consistent with the NERC style guide and IEEE usage for an SVC. No change made. We appreciate the explanation provided in the Extenuating Circumstances section. However, we believe that the standard should go beyond what is provided in the Sanction Guidelines. Why should an entity be held in violation in the event of multiple operations on its system during a natural disaster? There may not be an actual Misoperation but because an entity simply doesn't meet the purely administrative requirement of getting the evaluation done within a prescribed number of days, a violation has occurred. Recognition should be given in the standard for such events which withhold declaration of any potential violation until the entity has had sufficient time to 1) deal with the crisis at hand of rebuilding its system and 2) then performing the evaluations to determine if Misoperations occurred. This flies in the face of being innocent until proven guilty. **Response:** NERC and the Regional Entity do not have the authority to provide flexibility regarding the performance (timeframes) of a Reliability Standard in unique extenuating circumstances. However, the Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, the sanction guidelines provide sufficient flexibility to address extenuating circumstances in the event that they occur. No change made.

Organization	Yes or No	Question 3 Comment
		In the 2nd paragraph below Example R1a, insert 'where a' such that the 1st line reads: 'For the case, where a BES interrupting device...'In the 4th paragraph below Example R1a, insert 'the' in the 7th line between 'if' and 'entity'. **Response:** Punctuation correction and clarification made. In the 1st paragraph below Requirement R3, break the two sentences in the 7th-9th lines (clean copy) into two separate sentences such that it reads: 'The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a Misoperation and continue its investigation under Requirement R4.' **Response:** Corrections made. Bracket the 's' in 'CAP(s)' in the 4th line of the 2nd paragraph below Requirement R5 on Page 33 (clean copy). **Response:** Corrections made. Insert a 'to' between 'due' and 'resource' in the 4th line of the 2nd paragraph of Example R6c. **Response:** Corrections made. Regardless of the outcome of the capitalization of 'fault', it should be capitalized in the 1st sentence of Example R6d just like the 1st words of all the other examples given. **Response:** Corrections made.
American Electric Power	No	AEP recommends adding an example to the applications guideline to illustrate that a properly coordinated breaker failure operation does not equate to a "slow trip" type misoperation.

Organization	Yes or No	Question 3 Comment
		Response: The drafting team notes this is described in the first paragraph of the Guidelines and Technical Basis under the heading "Composite Protection System – Breaker Failure Example." No change made. AEP recommends adding a backup protection example to the application guidelines to illustrate how R2.2 would be applied. **Response:** The drafting team has provided an example(s) in the Guidelines and Technical Basis under the heading "Composite Protection System – Breaker Failure Example." Clarification made. AEP recommends adding an example of a breaker failure misoperation to the application guidelines. **Response:** The drafting team has provided an example(s) in the Guidelines and Technical Basis under the heading "Composite Protection System – Breaker Failure Example." Clarification made.
Public Service Enterprise Group	No	In comments for the prior posting, we addressed a "consistency" reporting issue. See our comments and the SDT's response in the Consideration of Comments document on pp 27-28 and the SDT's response which is incorporated into the standard in various places. See the Application Guideline change on p. 31 of the redline version, which included this addition: "The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure, it may decide to identify the operation as a Misoperation and continue its investigation until the entity determines otherwise. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation."

Organization	Yes or No	Question 3 Comment
		The SDT's language above still allows entities too much latitude in the classification of an operation as a correct Operation or a Misoperation. The classification of an operation as a correct operation or a Misoperation is step 1 in the process. Only if the operation is determined to be a Misoperation is the cause of the Misoperation investigated (step 2). We suggest this guidance: "If the available evidence IS INSUFFICIENT to classify the operation as a Misoperation PRIOR TO THE INVESTIGATION OF THE CAUSE OF A POSSIBLE MISOPERATION, DO NOT CLASSIFY THE OPERATION AS A MISOPERATION." A Misoperation with "no cause found" is not equivalent to a correct operation, which is how an unreported Misoperation is interpreted. If an entity classifies an operation as a Misoperation and goes down that path to investigate the cause, it may well conclude that no Misoperation occurred; however, unless its original Misoperation classification is changed to reflect that result, the reported Misoperations will be overstated. Another entity with an identical operation may decide not to classify it as a Misoperation based upon the data available to it absent an investigation of the cause. For the sake of consistent reporting, the classification decision (correct operation or Misoperation) must be reached without a causal investigation, which only takes place if an operation is classified as a Misoperation. **Response:** The performance under Requirement R1 is that the entity identify Protection System operations that are Misoperations. The requirement does not preclude the entity from using judgment in the classification of the operation if the available evidence is inconclusive. No change made.
Hydro-Québec	No	The purpose of the Standard shall be limited only to "Identify and correct the causes of Misoperations of Protection Systems affecting the reliability of the Bulk Electric System (BES)." The Bulk Electric System (BES) Elements or Protection System

Organization	Yes or No	Question 3 Comment
		Misoperations that may affect the reliability of the Bulk Electric System (BES), shall be first identifed by the PC or RC. **Response:** The scope of the current PRC-004-2.1a Reliability Standard applied to all BES Protection Systems; therefore, the Planning Coordinator or Reliability Coordinator do not need to identify specific BES Elements that affect reliability. No change made. Requirement R2 The owner of the interrupting device shall share any information he has, that could be used by the other owner of the protection system to determine the cause of the misoperation. **Response:** The drafting team contends that Requirement R2 only needs to require notification to the other owner(s) of the Composite Protection System. Creating Requirements for sharing information does little to improve reliability where information is already being communicated because the Requirements would have to prescribe what is shared and within what timeframes. No change made.
Nebraska Public Power District	No	See suggestion below in 4) **Response:** Please see response in Question #4.
Tacoma Power	No	In the Application Guidelines for Unnecessary Trip – Other Than Fault, the following paragraph seems out of place: “If a coordination error was at the remote terminal (i.e., set too fast), then it was an ‘Unnecessary Trip,’ category of Misoperation at the remote terminal.” This paragraph seems to focus on a scenario involving a fault. **Response:** The text was moved to “Unnecessary Trip – During Fault.” Correction made.

Organization	Yes or No	Question 3 Comment
		There is concern that, for a very small number of BES interrupting device operations, an entity could fail to identify (formally document) whether or not its Protection System component(s) caused a Misoperation. If this were to occur, it would likely be associated with apparently benign operations, so the likelihood that a misoperation would have occurred is low. Generally, misoperations garner a lot of attention within an entity, so they are generally hard to miss. Even if no misoperation occurred, an entity could be fined up to the maximum allowable for a Medium VRF and Severe VSL for failing to identify that its Protection System component(s) did not cause a Misoperation. The possibility for fines of this magnitude could drive potentially costly measures to ensure zero defects, even though BES reliability would not be impacted by failing to formally identify that an entity's Protection System component(s) did not cause a Misoperation. Tacoma Power agrees with the spirit of Requirement R1 but believes that compliance and enforcement should be assessed with failure (or tardiness in) identifying that its Protection System component(s) caused a Misoperation. Basically, if an entity does not determine whether or not a Misoperation occurred, they would be implicitly (by default) saying that a Misoperation did not occur. During an audit, if a BES interrupting device operation caused by a Protection System is uncovered for which no formal (explicit) identification according to Requirement R1 was made, the entity should only be found non-compliant (or penalized) if the CEA believes that a Misoperation did indeed occur. The purpose of the standard is to "identify and correct the causes of Misoperations of Protection Systems..." Perhaps this issue could be addressed in the Application Guidelines. **Response:** The performance under Requirement R1 is that the entity identify Protection System operations that are Misoperations. The requirement does not preclude the entity from using judgment in the classification of the operation if the

Organization	Yes or No	Question 3 Comment
		available evidence is inconclusive. The phrases "or not" have been removed from the VSLs to align with the Requirement. Even though Requirement R1, Part 1.1, stipulates that "the BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate," to what extent will entities be required to prove that BES interrupting device operations were not caused by a Protection System operation? The potential risk of failing to satisfy Requirement R1 seems high enough that entities may take costly measures to ensure zero defects, out of an abundance of caution, by excessively reviewing BES interrupting device operations. This additional cost could be better served in other areas to support BES reliability. Perhaps this issue could be addressed in the Application Guidelines. **Response:** The Requirement is written so that only Protection System operations that occur "under the circumstances Parts 1.1 through 1.3" be evaluated for Misoperation. No change made. In the Application Guidelines for Requirement R1, change "For the case,..." to "For the case in which a..." Furthermore, should this paragraph be included under the Requirement R2 portion of the Application Guidelines? **Response:** The drafting team provided an alternative clarification "For the case where a BES interrupting device..." Clarification made. The drafting team disagrees that this text needs to be included in the Guidelines and Technical Basis under Requirement R2. In the Application Guidelines for Requirements R1 and R3, change "The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion" to something like

Organization	Yes or No	Question 3 Comment
		“The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred.” The concern is that the CEA could require an entity to leverage all available data before determining that a Misoperation did not occur. **Response:** The drafting team added the clarification “In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred.” Clarification made. Tacoma Power appreciates the following paragraph in the Application Guidelines for Requirement R2: “A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the GO and TO functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.” **Response:** Thank you for your comment. In the Application Guidelines for Requirement R4, Example R4a, was the scheduling activity on 03/24/2014 considered to be the first investigative action pursuant to Requirement R4, or did the first investigative action pursuant to Requirement R4 occur on 4/10/2014?

Organization	Yes or No	Question 3 Comment
		Response: The drafting team added a clarification “as the first investigative” action to Examples R4b and R4b. Regarding Requirements R1, R3, and R4, is the date when an entity identifies that its Protection System component(s) caused a Misoperation the date that they officially make the identification? **Response:** Yes. As long as an entity is compliant with Requirement R1 or R3, as applicable, are they afforded some discretion as to the identification date? **Response:** The date a Misoperation is identified by the owner of the Protection System component(s) that caused a Misoperation would become the “official date” from which the Compliance Enforcement Authority would measure compliance with in Requirement R1 (or R3 for the notified entity). Note that if the “cause” of an identified Misoperation was not identified in Requirements R1 (or R3 for the notified entity), the entity is obligated under Requirement R4 to perform at least one investigative action at least once every two full calendar quarters after the Misoperation was first identified. No change made. It seems like the timeline for Requirement R4 should be based on 120 calendar days of the BES interrupting device operation, for Misoperations identified pursuant to Requirement R1, or the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, for Misoperations identified pursuant to Requirement R3. As written now, those entities who quickly identify Misoperations will have compliance obligations under Requirement R4 sooner. On the other hand, an entity that delays officially identifying a Misoperation could be looking for causes ahead of time such that they effectively bypass Requirement R4. Perhaps this issue could be addressed in the Application Guidelines. The objective here is not to make

Organization	Yes or No	Question 3 Comment
		the standard more complicated but to avoid misunderstanding that might surface during an audit. **Response:** Each of the time periods in the Requirements is discreet. Once a Misoperation is identified, the entity must either go to Requirement R4 (Misoperation without a cause) or Requirement R5 (develop a CAP because the cause is known). The drafting team added the "Requirement Time Periods" section to the Guidelines to provide additional clarity. Similarly, regarding Requirement R4 and R5, is the date when an entity determines the cause(s) of a Misoperation the date that they officially make the determination? **Response:** Yes. Perhaps this issue could be addressed in the Application Guidelines. Again, the objective here is not to make the standard more complicated but to avoid misunderstanding that might surface during an audit. **Response:** The drafting team provided clarification in the Guidelines and Technical Basis under the heading "Requirement Time Periods." Clarification made. In the Application Guidelines for Requirement R6, change "...were postponed due resource..." to "...were postponed due to resource..." **Response:** The drafting team corrected the grammar. If manual intervention in response to a Protection System failure to operate is required, this could imply that both the primary Composite Protection System and remote backup Composite Protection System(s) failed to operate, assuming that remote backup could be configured reliably to detect the fault under the pre-fault power system conditions. Would this condition automatically mean that multiple Composite Protection Systems, potentially at multiple locations (both primary and

Organization	Yes or No	Question 3 Comment
		remote backup), misoperated? Perhaps this issue could be addressed in the Application Guidelines. **Response:** Under the scenario described above, multiple "Failure to Trip" Misoperations and would been likely to have occurred. No change made.
Independent Electricity System Operator	No	We do not agree with the part on Composite Protection System, for the reasons indicated under Q1, above. **Response:** Please see the response under Question #1.
Oncor Electric Delivery LLC	No	Since the last Standard draft, the SDT has added a new example on page 29 of the Application Guideline which states "Example 7d: A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush following a maintenance outage. Only the high-side breaker opens since the low-side breaker had not yet been closed. Since closing the breaker put the transformer bank into service, this is a Misoperation." Although this scenario would be an undesired trip, without the low side breaker closed the transformer will not feed load. With that said, tripping of the high side will not compromise reliability of the BES although it is undesirable. Oncor has not seen a perfect relay that will respond ideally during the reenergization of a transformer with magnetizing current. For the reason just described, the possibility of tripping a transformer unnecessarily during energization (with no load connected) is preferable to desensitizing the protection further such that it might not operate when necessary. **Response:** The drafting team recognizes this situation; however, the scenario should be classified as a Misoperation. If so, the entity may address not making any changes to the Protection System under Requirement R5 by making a declaration why

Organization	Yes or No	Question 3 Comment
		corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken. No change made.
CenterPoint Energy	No	CenterPoint Energy recommends adding additional examples to help provide consistent reporting of Misoperations. Examples for Breaker failure events (stuck breaker) and additional examples of the more common "Unnecessary Trip – During Fault" category would be helpful. Additional examples would help clarify the interrelationship between the "Slow Trip – During Fault" and the "Unnecessary Trip – During Fault" categories. The following comments and additional examples are provided for consideration: **Response:** The drafting team has provided examples (see Examples 3b, 5b, and the 3rd bullet under the section "Composite Protection System – Breaker Failure Example") in the Guidelines and Technical Basis. Clarification made. Example 1e: The Composite Protection System for a bus does not operate during a bus fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one "Failure to Trip – During Fault" Misoperation of the bus Composite Protection System. **Response:** The drafting team has provided an Example 1e in the Guidelines and Technical Basis. Clarification made. Example 3b: A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical fault clearing time for a line fault in conjunction with a breaker failure (stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element's Composite Protection System. If

Organization	Yes or No	Question 3 Comment
		a generating unit's Composite Protection System operates due to instability caused by failure of a breaker's Composite Protection System, it is not an "Unnecessary Trip – During Fault" Misoperation of the generating unit's Composite Protection System. This event would be a "Slow Trip – During Fault" Misoperation of the breaker's Composite Protection System. **Response:** The drafting team has provided this Example 3b, almost verbatim, in the Guidelines and Technical Basis. Clarification made. Example 3c: A line connected to a generation interconnection station is protected with two independent high-speed pilot systems due to dynamic stability reasons. The Composite Protection Scheme for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a fault on this line, the two pilot systems fail to operate; and, the time-overcurrent scheme operates clearing the fault with no generating units or other Elements tripping (no over-trips). This event is not a Misoperation. **Response:** The drafting team has provided an Example 3c in the Guidelines and Technical Basis. Clarification made. Example 3d: A line connected to a switching station is protected with two independent high-speed pilot systems for reasons other than voltage or dynamic stability (e.g., short line length or to reduce backup clearing times for service reliability). The Composite Protection Scheme for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. The step distance and time-overcurrent schemes and Protection Systems of other line terminals are intentionally not coordinated with the step distance and time-overcurrent schemes of this line because high-speed tripping is expected on the line with the two independent high-speed pilot systems. During a fault on the line with the two independent high-speed pilot systems, the two pilot systems fail to operate; however, the time-

Organization	Yes or No	Question 3 Comment
		overcurrent scheme operates clearing the fault however, another line in the system trips (over-trips). The trip of the other line in the system is not an "Unnecessary Trip – During Fault" Misoperation as miscoordination was expected for the conditions that occurred. The event on the line with the two pilot systems is a "Slow Trip – During Fault" Misoperation, although the analysis and Corrective Action Plan would address the two pilot schemes failure to trip. **Response:** The drafting team notes this example is unnecessary due to its complexity therefore it has not been included in the Guidelines and Technical Basis. No change made. Example 5b: An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared fault on a different line is a Misoperation. The fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip of the line protection; therefore, the non-faulted line Protection System operation is an "Unnecessary Trip – During Fault" Misoperation. **Response:** The drafting team has provided an Example 5b in the Guidelines and Technical Basis. Clarification made. Example 5c: A line connected to a switching station is protected with two independent high-speed pilot systems for reasons other than voltage or dynamic stability (e.g., short line length or to reduce backup clearing times for service reliability). The Composite Protection Scheme also includes step distance and time-overcurrent schemes in addition to the two pilot systems. The step distance and time-overcurrent schemes and Protection Systems of other line terminals are intentionally not

Organization	Yes or No	Question 3 Comment
		coordinated with the step distance and time-overcurrent schemes of this line because high-speed tripping is expected on the line with two independent high-speed pilot systems. During a fault on the line with two independent high-speed pilot systems, the two pilot systems fail to operate; however, the time-overcurrent scheme operates clearing the fault and, in conjunction, another line in the system trips (over-trips). The trip of the other line is not an “Unnecessary Trip – During Fault” Misoperation as miscoordination was expected for the conditions that occurred. The event on the line with the two pilot systems is a “Slow Trip – During Fault” Misoperation, although the analysis and Corrective Action Plan would address the schemes failure to trip. **Response:** The drafting team notes this example is unnecessary due to its complexity therefore it has not been included in the Guidelines and Technical Basis. No change made. Additionally, in the Application Guidelines, it appears the following paragraph at the end of the “Unnecessary Trip – Other Than Fault” examples is misplaced and could be deleted: “If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip," category of Misoperation at the remote terminal.” **Response:** The drafting team has relocated the text in the Guidelines and Technical Basis. Clarification made. CenterPoint Energy recommends adding the following wording as the last two paragraphs at the end of the examples for “Unnecessary Trip – During Fault” examples to parallel the wording for the “Slow Trip – During Fault” category: In analyzing the Protection System for Misoperation, the entity must also consider the “Slow Trip – During Fault” category to determine if an “slow trip” applies to the Protection System operation of an Element other than the faulted Element.

Organization	Yes or No	Question 3 Comment
		Response: The drafting team disagrees that the suggestion “In analyzing…” provides additional clarity. No change made. If a coordination error was at the remote terminal (i.e., set too fast), then it was an " Unnecessary Trip – During Fault" category of Misoperation at the remote terminal. **Response:** The drafting team has provided an Example 5c in the Guidelines and Technical Basis. Clarification made.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	The clarifications and additions to the Application Guide are helpful to the understanding of the standard. We recommend these type of guides be with all proposed Standards in the future. **Response:** Thank you for your comment. Results-based Standards (RBS) are designed to have an Application Guideline section to be retained with the adopted PRC-004-3 Reliability Standard upon approval.
National Grid	Yes	
Dominion	Yes	
Duke Energy	Yes	
SERC Protection and Controls Subcommittee	Yes	(1) It would be beneficial if examples in the Application Guidelines had different solutions other than just ‘fixed capacitor’. **Response:** The drafting team contends that the examples illustrate different Corrective Action Plan approaches within the Requirement. Replacing the capacitor

Organization	Yes or No	Question 3 Comment
		simplifies the example to highlight the differences in what corrective actions are being taken. No change made. (2) It would be beneficial and we recommend the Application Guidelines remain with the Standard when published to provide easy reference for users. To provide clarity about the authority of the guidelines, the following note should be included similarly as written in other Standards that include Application Guidelines: "Note: These Application Guidelines for PRC-004-3 are neither mandatory nor enforceable." **Response:** Thank you for your comment. Results-based Standards (RBS) are designed to have a Guideline and Technical Basis section to be retained with the adopted PRC-004-3 Reliability Standard upon approval. Only the Requirements are mandatory and enforceable. No change made.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	Application Guidelines: Overall, this document is very good in addressing the process. **Response:** Thank you for your comment.
ACES Standards Collaborators	Yes	(1) We agree that the Application Guidelines include improved examples and did clarify the intent of the drafting team. Furthermore, we support the intent in the

Organization	Yes or No	Question 3 Comment
		application guidelines. However, in some cases, the intent of the drafting team and the language of the requirements simply do not align. For example, language was inserted into the Requirement R3 discussion on page 31 to clarify that a registered entity is “to classify an operation as Misoperation if the available information leads to that conclusion” and “allows an entity to classify an operation as a Misoperation if an entity is not sure.” Neither Requirement R3 nor Requirement R1 language provide this flexibility and is thus inconsistent with the language in the application guidelines. R1 and R3 are both very clear that the responsible entity has 120 days (for R3 or the later of 60 days after notification) to identify whether its Protection System operations were a Misoperation. This language is definitive. We do not see how this language allows an entity to classify an operation as Misoperation if it is not sure. Again, the requirement language states clearly that the responsible entity has to identify whether its Protection System components result in a Misoperation. There is no room in the language of the requirement for uncertainty. This further leads to a problem with R4 because R4 would require R1 and R3 to be violated since both require determination of whether a Misoperation occurred and R4 identifies a situation that can only occur after a violation of R1 or R3. Even the last Severe VSL for both R1 and R3 supports our argument. Failure to identify a whether or not a Protection System operation is a Misoperation is a Severe VSL. We suggest the drafting further refine Requirements R1, R3, and R4 collectively to match the intent demonstrated in the application guidelines. **Response:** The performance under Requirement R1 is that the entity identify Protection System operations that are Misoperations. The requirement does not preclude the entity from using judgment in the classification of the operation if the available evidence is inconclusive. The drafting team contends that the language in the

Organization	Yes or No	Question 3 Comment
		Guidelines and Technical Basis provides clarity on the intent of the Requirements (i.e., R1 and R3), and is consistent with requirement language. No change made.
Florida Municipal Power Agency	Yes	FMPA appreciates the changes to the Application Guide and does feel the additional specificity was beneficial. We do, however, feel some sections are inconsistent with the revised Requirements and definitions in the standard. See our comments on the definition of "Misoperation" above. There may be some additional changes that are needed to the Application Guide to ensure it fully supports the revised Standard. **Response:** Please see our previous responses to FMPA comments. No change made.
Bonneville Power Administration	Yes	
Operational Compliance	Yes	
Exelon Companies	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc	Yes	
Xcel Energy	Yes	
Wisconsin Electric Power Company	Yes	

Organization	Yes or No	Question 3 Comment
Entergy Services, Inc.	Yes	Entergy agrees with the SERC PCS comments to add Application Guideline examples other than "fixed capacitors", and that the Application Guideline should remain with the standard as a reference. **Response:** Please see response to SERC PCS comments. The Guidelines and Technical Basis remains with the standard. No change made.
American Transmission Company	Yes	
Kansas City Power & Light	Yes	
Ingleside Cogeneration LP	Yes	ICLP found the examples provided in the Applications Guidelines to be helpful. In addition, there is a sufficient diversity in scope that will act as a useful reference in the event that we suspect a Misoperation of one of our Composite Protection Systems may have taken place. **Response:** Thank you for your comment.
Idaho Power	Yes	
Southern California Edison Company	Yes	
Omaha Public Power District	Yes	
Cleco	Yes	
Northeast Utilities	Yes	The examples provided in the application guideline should be clarified when talking about unnecessary trips. It should be made clear that if any portion of a Composite

Organization	Yes or No	Question 3 Comment
		Protection System designed to protect one Element operates for a problem on another Element is considered a Misoperation. **Response:** The drafting team added a number of examples to clarify "unnecessary trips" in the Guidelines and Technical Basis. A Composite Protection System designed to protect one Element that operates for a problem on another Element is not necessarily a Misoperation. It could be a correct operation for a "Failure to Trip" elsewhere. Clarifications made to the Guidelines and Technical Basis.
Tri-State Generation and Transmission Association, Inc.	Yes	
Flathead Electric Cooperative, Inc.	Yes	still have trouble with how the word composite is being used, but do agree that the guidelines provide clarity on the drafting teams intent, unsure the compliance impact on the requirements **Response:** Thank you for your comment.
Wolverine Power Supply Cooperative, Inc.	Yes	
Texas Reliability Entity		No comments.

4. If you have any other comments on this Standard that were not provided in response to the previous questions, please provide them here:

Summary Consideration: The numerical values are approximate and are intended to provide a gauge of the concerns raised by industry stakeholders. The number of comments noted is analogous to the number of entities (e.g., five comments means five entities provided a comment). The following summary does not include items addressed in the previous summaries.

This section contained two individual comments that were different from previous summaries above. The comment suggested updating the flowchart wording based on clarifications made to the standard. The drafting team updated the draft PRC-004-3 Reliability Standard, its flowchart, and other related project documents for alignment such as the Implementation Plan which earlier posting revisions to the Misoperation definition failed to include.

Second, an entity pointed out that Evidence Retention section states 12 months is the required evidence retention period for the Requirements. The commenter also noted that the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit. The drafting team clarified the evidence retention periods are "a minimum of" time an entity is required to retain specific evidence to demonstrate compliance. The drafting team used NERC guidance in determining the appropriate minimum evidence retention periods.

The following multiple minority comments did not result in a clarification or revision to the draft PRC-004-3 Reliability Standard or other related project documents. Five comments by 15 individual presented general questions to the drafting team. The drafting team provided responses to these questions; for example, responses included as to whether the scenario was a Misoperation, not a Misoperation, or other response applicable to the rationale of certain Requirements. Three comments by 35 individuals requested either information on why topics like undervoltage load shedding (UVLS), and dispersed generation resources (DGR) concerning the new BES definition implementation, were not addressed in this version. The drafting team noted that it cannot base criteria or applicability in the proposed draft PRC-004-3 Reliability Standard based on projects that are in active development. Completing this version three will enable other drafting teams to address UVLS and DGR topics. Two comments represented by four individuals were concerned about the amount of time to develop a Corrective Action Plan (CAP) in Requirement R5. The drafting team contends that 60 calendar days is an adequate amount of time to develop a high level evaluation and plan. Timeframes associated with any actions taken as a part of the evaluation of other Protection Systems are outside the scope of the standard. Two individual comments suggested significant changes to the standard. The drafting team contends that the draft PRC-004-3 Reliability Standard as written achieves the stated Purpose and therefore declines to make wholesale modifications to the Requirements. For example, there is no requirement to provide a CAP to the Reliability Coordinator in the current version PRC-004-2.1a Reliability Standard, although Regional procedures may have dictated the entity to do so.

The following are comments from single entities and individuals. There was a comment concerning the review and reporting of operations of jointly-owned Composite Protection System components as opposed to multiple entities owning separate components. The drafting team contends that the reporting of Misoperations is outside the scope of the draft PRC-004-3 Reliability Standard and is being addressed by the NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., “data request”). Absent an agreement, all owners of a Protection System will have a compliance responsibility. Also, one comment asked when is a change to a CAP considered failure to implement. The drafting team noted that modifying a CAP does not constitute a failure to implement a CAP. According to Requirement R6, the audit approach to determining a failure to implement a CAP is addressed by the previously posted draft Reliability Standard Audit Worksheet (RSAW). As the entity completes the actions within a CAP, the entity will update the CAP periodically, thus the CAP will demonstrate implementation.

Another single entity commented that an entity in Requirement R3 should be afforded a full 120 calendar days to review its Protection System similar to entities that initiate reviews under Requirement R1. The drafting team responded that when an entity receives notification of a Protection System operation by the BES interrupting device owner, the Protection System owner is allotted a minimum of 60 calendar days to identify whether it was a Misoperation and could be as much a 120 calendar days from the date the BES interrupting device operated depending on when notification occurs. A minimum time period that is less than 120 calendar days is provided on the basis that the BES interrupting device owner has already performed preliminary work, collaborated with the other owners, and that other owners generally have fewer associated Protection System components.

Another entity commented that an entity could forego performing Requirement R1 or R3 and conduct its review under Requirement R4. The drafting team contends that Requirements R1 and R3 do not preclude an entity from determining the cause of an identified Misoperation (Note: Requirement R2 is for notification to others.); however, Requirement R4 becomes applicable only after a Protection System operation is “identified as a Misoperation” under Requirement R1 or R3 and does not have an identified cause. Requirement R4 is an exception-based Requirement and is only performed when the entity did not identify the cause(s) of the Misoperation in its performance in either Requirement R1 or R3.

Last, a single commenter suggested shortening the performance time periods in Requirement R4 for performing investigative action. The drafting team contends that the periodic action balances the compliance burdens and focuses the entity’s effort on determining the cause(s) of the Misoperation while providing measurable evidence. In addition, certain planned investigative actions may require months or years to schedule and complete due to outages and other factors. Additionally, the drafting team contends that listing a defined time limit to complete the Requirement would actually decrease reliability. Shortening time limits would have the unintended consequence of causing an entity to discontinue its investigation. The Requirement allows the entity to either determine the cause or conclude its investigation when it is confident that a cause cannot be determined.

Organization	Question 4 Comment
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	a) The multiple timing process periods are an added burden and still unclear in the standard. However, the application notes do provide some guidance {R3}; **Response:** The drafting team provided clarification in the Guidelines and Technical Basis under the heading "Requirement Time Periods." Clarification made. b) The wording in R3 of the Process Flow Chart on the last page of the draft standard should match that of the requirement R6 (change "greater" to "later" in the chart). There is no evidence that entities have not been doing due diligence in investigating and correcting misoperations, therefore, the addition of the various timelines serve only to generate additional paperwork. **Response:** The drafting team has corrected the wording in the flowchart. Correction made.
ACES Standards Collaborators	(1) Example 3 on page 25 should be updated. The first sentence is inconsistent with the proposed definition of Misoperation. A failure of a line's Composite Protection System to operate as quickly as intended is only a Misoperation if another Element's Composite Protection System operation. Please append the following clause to the first sentence: "if another Element's Composite Protection System operated." **Response:** Clarification made. (2) The VSLs for R3 rely only on the 120 day portion of the language in the requirement. They do not include the "later of" language relying on 60 days if more than 60 days has passed since the original Protection System Operation. We suggest the VSLs should be updated accordingly reflect the requirement in totality.

Organization	Question 4 Comment
	Response: The VSL is based on tardiness regardless of whether the entity is afforded 120 calendar days from the operation of the BES interrupting device or 60 calendar days of notification by the initiating entity pursuant to Requirement R2. No change made. (3) To avoid requiring a registered entity from providing all BES interrupting device operations, the Compliance Assessment Approach for R1 in the RSAW needs to be modified to be consistent with the requirement and the evidence request section. The auditor should only sample BES interrupting device operations that meet the criteria Requirement R1 Part 1.1 through 1.3 and is provided as evidence in the evidence requested section. Please add “that meet criteria Requirement R1 Part 1.1 through 1.3” after “interrupting device operations” in the first and second rows of the RSAW’s Compliance Assessment Approach for R1. **Response:** The drafting team has provided the RSAW comment to NERC Compliance for consideration and modification. (4) Please update the RSAW’s Note to Auditor section to review the Application Guidelines section for Requirement R2 for small entities as well as vertically integrated utilities. The Application Guidelines make clear that small entities with a single protection engineer are not expected to provide notification requirements between the GO, TO and DP because they would already be aware since they evaluate all Protection System operations including transmission and generation. **Response:** This concern is addressed in the paragraph following Example R2b in the Guidelines and Technical Basis under the heading “Requirement R2.” The drafting team has provided the RSAW comment to NERC Compliance for consideration and modification. (5) Thank you for the opportunity to comment.
CenterPoint Energy	(a) In the Application Guidelines, CenterPoint Energy recommends changes to account for high-speed tripping for internal transformer faults by other types of protection systems (e.g., sudden pressure) that are not specifically included in the proposed definition of Composite Protection System. The following additional wording at the end of Examples 1a and 1b is suggested:

Organization	Question 4 Comment
	Example 1a: A failure of a transformer's Composite Protection System to operate for a transformer fault is a Misoperation unless other protection schemes (e.g., sudden pressure) operated. Example 1b: A failure of a "primary" transformer relay (or any other component) to operate for a transformer fault is not a “Failure to Trip – During Fault” Misoperation as long as another component of the transformer's Composite Protection System or other protection schemes (e.g., sudden pressure) operated. **Response:** The drafting team contends that the scenario that is described does not meet the definition of “Misoperation.” For a high impedance transformer Fault, the non-operation of a differential relay due to low Fault current levels is not a failure to operate as intended for protection purposes. A similar example (R1b) has been added to the Guidelines and Technical Basis. Clarification made. (b) The proposed Requirement R4 wording currently includes the following: “...shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes...”. CenterPoint Energy understands this wording is to provide a mechanism to continue investigative work to determine the cause of a Misoperation when the cause cannot be determined during the allotted time periods in Requirements R1 or R3. CenterPoint Energy recommends additional wording to allow the investigation to be completed in the quarter that the misoperation occurs (“partial quarter”) for cases where the investigation and tests, including any needed outages< can be completed in the partial quarter and suggests the following wording: “...shall perform investigative action(s) to determine the cause of the Misoperation at least once during the partial quarter when the misoperation occurs or every two full calendar quarters after the Misoperation was first identified, until one of the following completes...”.

Organization	Question 4 Comment
	Response: The drafting team contends that the suggestion does not provide any additional benefit over the current wording and may have the unintended consequence of shortening the time period for performance and being in compliance. See Example R4a in the Guidelines and Technical Basis for additional detail. No change made.
Florida Municipal Power Agency	2. FMPA does not feel our previous comment regarding the inherent problems with the concept of comparing Protection System performance to a single set of generic categories as tied to compliance was addressed. We feel many of the issues and challenges in this revised standard would easily be addressed by allowing entities to compare the performance of their relays with their Protection System Design Philosophy. In the absence of a mandatory electric reliability standard, this is how Utilities would determine "mis-operations" – did the Protection System/component perform according to the intended design? **Response:** The drafting team contends that design philosophies inherently include the principles of dependability and security. Each entity using its particular design philosophy would lead to less consistent classification of Misoperations. No change made. 3. In the Facilities section – what is the reason PRC-004-3 cannot use the same description of "Protection System" as PRC-005-2? Would these two standards not inherently be designed to cover the very same Facilities? **Response:** The draft PRC-004-3 Reliability Standard uses the defined term in the *Glossary of Terms Used in NERC Reliability Standards* without the additional level of specificity provided in PRC-005-2. The reasoning was to avoid a subsequent change to the draft PRC-004-3 Reliability Standard if additional equipment changed in the future. No change made. 4. FMPA accepts the SDT's revised definition of Composite Protection system which no longer singles out step-distance/intentional remote backup schemes. However, we in general do not agree with the use of Composite Protection System in the standard. This term is being used to reduce what is considered a "Misoperation". While FMPA supports more relaxed Requirements for

Organization	Question 4 Comment
	mitigating/remediating a Misoperation when another part of the Composite Protection System successfully prevents any negative impact to the BES, a Misoperation is still a Misoperation. If the goal is to keep statistics on how we are doing as an industry, we need to tie those statistics to basic characteristics that are less subject to interpretation and change. Misoperation should still be tied to the failure of equipment. The fact that a different part of the Composite system properly functioned is additional information. Again, we support the idea that a properly designed Composite Protection system should mean an entity does not necessarily need to make changes, but the Misoperation should still be tracked. **Response:** The drafting team contends that "Composite Protection System" should be based on the principle that an Element's multiple layers of protection are intended to function collectively. Also, the new definition supports consistent reporting of Misoperations under the Section 1600 data request because all entities, under the new definition, will be evaluating their Composite Protection Systems in the same manner. No change made. 5. What is the reason the defined Glossary term "Fault" has been replaced with "fault" throughout the document? **Response:** The drafting team re-evaluated the general use of "fault" and the *Glossary of Terms Used in NERC Reliability Standards* definition of "Fault." The evaluation resulted in reverting certain occurrences that should refer to the glossary definition. Clarification made.
Tacoma Power	Although the term is discussed in the Application Guidelines, consider formally defining the term "interrupting device." **Response:** The drafting team asserts that the phrase "BES interrupting device" is widely understood by industry and is described in the Guidelines and Technical Basis under the heading "Definitions." No change made. In Requirement R3, should "BES interrupting device(s)" be "BES interrupting device"?

Organization	Question 4 Comment
	Response: The parenthetical "s" is added here because the Protection System may have tripped more than one BES interrupting device. No change made. In Requirement R4, should "the cause" be "the cause(s)"? **Response:** Parenthetical "s" added. In Requirement R5, should "a cause" be "the cause" or "the cause(s)"? **Response:** This use of "cause" is singular because the Corrective Action Plan timing is triggered off of the "first" identified cause. No change made. In the Rationale for R6, change "tivities" to "activities." **Response:** Correction made.
American Electric Power	As currently written, R5 may be interpreted as requiring the entity to both develop a CAP and complete the evaluation of the CAP's applicability to other Protection Systems within 60 days. **Response:** Yes, that is correct. For large entities, or in cases where the evaluation requires equipment outages, completing the evaluation of applicability within 60 days could be impossible. R5 should be revised to clearly state that the entity is only required to develop a CAP within 60 days. There should be an option to include the evaluation within the CAP. This would enable entities to complete the evaluation as part of the CAP and within a time window that is tailored to the scope of the corrective action and quantity of potentially applicable Protection Systems. AEP supports the concept of evaluating a corrective action's applicability to other Protection Systems. **Response:** The drafting team contends that 60 calendar days is an adequate amount of time to develop a high level evaluation. Timeframes associated with the execution of the evaluation are outside the scope of the standard. No change made.

Organization	Question 4 Comment
	However, the standard requirements provide no means of measuring what is an adequate evaluation. Without this, an auditor could question the adequacy of an entity's evaluation, decide that the entity's actions were not an evaluation and subsequently find the entity non-compliant with R5. We believe that the SDT's Application Guide examples were an effort to demonstrate what would be acceptable. However, the examples are not exhaustive and therefore do not eliminate the audit risk. AEP believes that subject matter experts are in the best position to determine evaluation scope and content. AEP recommends that in lieu of adding additional examples in the Application Guideline, the drafting team should consider the possibility of an auditor invalidating an evaluation. The requirement should be revised so that it places bounds on this scenario and provide entities with certainty in how R5 might be reviewed by an auditor. **Response:** The drafting team contends that there are no provisions within the draft PRC-004-3 Reliability Standard directing an auditor to determine the adequacy of an evaluation. No change made. AEP supports the overall efforts of the drafting team in the fundamental approach taken in the proposed standard. AEP has chosen to vote in the affirmative despite our concerns regarding the CAP and evaluation within R5, and how their compliance would ultimately be determined by an auditor. **Response:** Thank you for your comment and support.
Independent Electricity System Operator	As indicated in our previous comments, we disagreed with the omission of UVLS while UFLS is included. The SDT's response indicates that UVLS has not been included in the proposed standard's Applicability because Misoperations of UVLS relays are being addressed under Project 2008-02 - Undervoltage Load Shedding when modifying Reliability Standard PRC-022-1 - Under-Voltage Load Shedding Program Performance. We do not find this rationale sufficient to justify the inclusion of UFLS but exclusion of UVLS since both need to be assessed and treated under the same light. Note that the SAR for Project PRC-022-1 is being revised to include UFLS. We suggest the PRC-004 SDT to

Organization	Question 4 Comment
	coordinate with the PRC-022 SDT to apply a consistent approach to addressing Misoperations of UFLS and UVLS. **Response:** Undervoltage load shedding (UVLS) has not been included in the draft PRC-004-3 Reliability Standard's Applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Adding UVLS in PRC-004-3 at this point would create unforeseen issues with having Requirements in two different Reliability Standards address the same activity. The purpose of the UFLS project is to address an outstanding FERC directive and review PRC-006-1 to determine if any steady state modifications are appropriate (i.e., Paragraph 81 criteria and recommendations of the Independent Expert Review Panel). Specifically, the other project's standard drafting team will revise PRC-006-1 to address the directive included in FERC Order No. 763 and to provide for clear, unambiguous design and documentation requirements for automatic UFLS programs. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard. The drafting team added additional text to the background to explain both UVLS and UFLS. Clarification made.
Bonneville Power Administration	BPA believes that there is one other gap that has not been identified. This is the case where a TO, GO, or DP owns a BES interrupting device that operates, but does not own any of the Composite Protection System. This is a real scenario. In this situation, the owner of the BES interrupting device is not subject to R1 because R1.2 is not true, i.e. the owner of the BES interrupting device does not own all or part of the Composite Protection System. Likewise, the owner of the BES interrupting device is not subject to R2 because R2.1.1 is not true, i.e. the owner of the BES interrupting device does not share ownership of the Composite Protection System -- they don't have any ownership of the Composite Protection System. With the owner of the BES interrupting device not subject to R1 or R2, the operation of the BES interrupting device would not be investigated. BPA suggests that this problem could be remedied with a slight change in language to R2.1.1 as follows: "The BES interrupting device owner does not own any of the Composite Protection System or shares the

Organization	Question 4 Comment
	Composite Protection System ownership with any other owner." This change would require an owner of a BES interrupting device that does not own any of the Composite Protection System to provide notification of the operation to the owners of the Composite Protection System within 120 days per R2.1 so that they could then investigate the operation. **Response:** The drafting team asserts that according to definition of Protection System which became effective April 1, 2013, the BES interrupting device owner owns a component of the Protection System, namely the trip coil(s) of that BES interrupting device (at a minimum). No change made.
Cleco	Cleco will continue to vote "Negative" as long as the SDT continues to support in R1 and R2 the deadline of 120 days to determine if an operation is a misoperation. There should be exceptions built into the standard when there are circumstances that create numerous outages such as ice storms or hurricanes. For example; In FAC-003, a footnote allows for circumstances that are beyond the control of the Registered Entity. Also, the standard should apply to all protection systems and the SDT should not exclude SPS or RAS. **Response:** We understand your concern, however, the Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, the sanction guidelines provide sufficient flexibility to address extenuating circumstances in the event that they occur. Remedial Action Schemes (RAS) and Special Protection Systems (SPS) are being addressed by Project 2010-05.2 – Special Protection Systems (Phase 2 of this project). No change made.
Tennessee Valley Authority	Currently, there is not a clear indication of regulatory relief for an entity following a major natural disaster. When recovering from major events such as Hurricane Sandy, the first priority is to get lights on and rebuild the system. Because a large natural event produces an influx of unique system

Organization	Question 4 Comment
	configurations that may not have been planned for by system planners or relay setters, analyzing and investigating all the operations and misoperations that occur takes months and is not the top priority for a utility that endures such an event. We respectfully request that the standard drafting committee add wording that states something similar to the following. In the event that the reporting entity is the victim of a weather related Category 4 or 5 event, 90 days are added to each of the required deadlines for misoperations caused by the weather related event. **Response:** NERC and the Regional Entity do not have the authority to provide flexibility regarding the performance (timeframes) of a Reliability Standard in unique extenuating circumstances. However, the Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, the sanction guidelines provide sufficient flexibility to address extenuating circumstances in the event that they occur. No change made.
Electric Reliability Council of Texas, Inc.	ERCOT is concerned about Requirement 1 that allows entities 120 days to identify a misoperation. ERCOT believes this might negatively impact the reliability of the grid. Currently, entities have the responsibility to analyze disturbances to identify misoperations. A misoperation could indicate a greater threat to reliability and that threat could exist, unknown, for several months while entities make determinations if operations are truly a misoperation. **Response:** The drafting team concluded that most Protection System reviews would occur soon after a BES interrupting device operation. The 120 calendar days is a maximum time allowance and provides for seasonal variations in operations and work load and the opportunity to identify any Misoperations which were initially missed. No change made.

Organization	Question 4 Comment
	The responsible entity under the new Standard will track misoperations and develop Corrective Action Plans (CAPs). There is no responsibility for the entity to share that information with Reliability Coordinators who have the responsibility for the wide area view of their Reliability Coordinator area. ERCOT is also concerned that while the responsible entity may develop CAPs, there is no responsibility of coordination of the CAP with other potentially affected entities. **Response:** If a CAP results in a modification to a Protection System, PRC-001 – System Protection Coordination requires coordination with other owners. No change made. ERCOT is therefore recommending the following: R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 24 hours, identify whether its Protection System component(s) caused a Misoperation on an element that is part of an Interconnection Reliability Operating Limit under the following circumstances: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning] 1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and 1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and 1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation. R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 2 business days, identify whether its Protection System component(s) caused a Misoperation on an element at 200 kV or more under the following circumstances: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]

Organization	Question 4 Comment
	2.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and 2.2 The BES interrupting device owner owns all or part of the Composite Protection System; and 2.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation. R3. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 5 business days, identify whether its Protection System component(s) caused a Misoperation on an element that is a BES element under the following circumstances: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning] 3.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and 3.2 The BES interrupting device owner owns all or part of the Composite Protection System; and 3.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation. R7. Each Transmission Owner, Generator Owner, and Distribution Provider shall provide the CAP developed in R5, to the Reliability Coordinator with the expected date of completion, how the Composite Protection System will operate until the CAP is completed and detailed information of how the entity will coordinate the CAP with other affected entities if applicable. **Response:** The drafting team contends that the draft PRC-004-3 Reliability Standard as written achieves the stated Purpose and therefore declines to make wholesale modifications to the Requirements. There is no requirement to provide a Corrective Action Plan to the Reliability Coordinator in the current version (i.e., PRC-004-2.1a) of the standard, although Regional procedures may have dictated the entity to do so. No change made.

Organization	Question 4 Comment
Wisconsin Electric Power Company	Facilities, Section 4.2.1, should have an exclusion for individual dispersed generators, or have its applicability limited to the point where the generators are aggregated to greater than 75 MVA. It is critical for the PRC-004-3 SDT to coordinate with the SDT for Project 2014-01, Standards Applicability for Dispersed Generation Resources, to assure that the new standard will have appropriate applicability consistent with BES reliability. **Response:** It is not practical to implement changes to the draft PRC-004-3 Reliability Standard based on another project that is in active development. The standard drafting team for Project 2014-01 is aware of this concern and will be addressing the topic following adoption of the draft PRC-004-3 Reliability Standard. No change made.
Flathead Electric Cooperative, Inc.	Generally feel that the requirements should be the sole place where the actual compliance requirements appear. Lot of information in measures, application guidelines, definitional changes that are not technically requirements but may be treated as such depending upon the audience. **Response:** The Requirements of the draft PRC-004-3 Reliability Standard are the only requirements an entity must follow to be compliant. Other information such as Measures and Guidelines and Technical Basis support measurement, provide clarity, and intent of the standard. No change made.
Tri-State Generation and Transmission Association, Inc.	In response to Tri-State's previous concern to the review and reporting of operations of jointly-owned Composite Protection System components as opposed to multiple entities owning separate components. The SDT stated "While a Protection System may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results" appears to require all entities to report the operation giving double jeopardy to each misoperation on jointly-owned Composite Protection System components, unless a contract speaks to the designated "Compliance Entity". Typically compliance contracts take some time to come to fruition.

Organization	Question 4 Comment
	Is it the drafting team's intent that misoperations be reported by multiple entities in this situation until a contract is finalized? **Response:** The reporting of Misoperations is outside the scope of the draft PRC-004-3 Reliability Standard and is being addressed by the NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., "data request"). Absent an agreement, all owners of a Protection System will have a compliance responsibility. No change made.
Pepco Holdings Inc	None
Oncor Electric Delivery LLC	Oncor initially balloted affirmative; however, based on the changes in the Application Guide, Oncor's ballot position has changed. Oncor's comments have been provided for the SDT's consideration (response to Question #3) Oncor requests the SDT please consider the additional comment below: In "R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation under the following circumstances: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning] 1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and 1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and 1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation."

Organization	Question 4 Comment
	The circumstances mentioned in 1.1 and 1.3 cause confusion when you do not have a protection system component cause the BES interrupting device operation in the event a BES device is operated by manual intervention. Oncor recommends that 1.3 be written to state: The BES interrupting device owner identified that its Protection System component(s) were designed to cause the BES interrupting device(s) operation. **Response:** The drafting team made a clarification to Requirement R1, Part 1.3 to address this oversight. Part 1.3, as intended, now includes “manual intervention” as a circumstance. Clarification made. The request below is an outstanding request from Oncor’s previous comment period: The Extenuating Circumstances process, as outlined on page 30 of the Application Guidelines, relies too heavily on a subjective review by Enforcement to determine whether penalties will be imposed. In alignment with the Reliability Assurance Initiative Oncor recommends the evaluation of an Extenuating Circumstance be initially reviewed by Compliance Operations in accordance with the system-wide and regional risk framework, an entity’s inherent risk assessment and controls to ensure extenuating circumstances are not evaluated as a “one size fits all” and findings are determined in accordance with RAI versus an automatic Enforcement path. Furthermore, Oncor recommends the Registered Entity be allowed to request a formal "state of extenuating circumstance" and coordinate an extension to the 120 day deadline with the Regional Entity. **Response:** The drafting team does not have the ability to make modifications to the Rules of Procedure. No change made.
Exelon Companies	Paraphrasing many commenters from draft 4, Exelon agrees emphasis on due dates from the time of an operation be reconsidered. There is a significant administrative burden imposed by the proposed approach not commensurate with gains in reliable operations. The drafting team can review previous comments to this effect as well as references to the use of “calendar” as used in the PRC-005

Organization	Question 4 Comment
	supplemental reference to preclude the need to have reviews done by a specific date. We disagree with the SDT response that timeframes as proposed are required to force entities to be diligent about identifying and correcting misoperations. **Response:** The drafting team contends that the timeframes should be measured from the operation date of the BES interrupting device which makes the use of calendar months or quarters difficult. The drafting team concluded that most Protection System reviews would occur soon after a BES interrupting device operation. The 120 calendar days is a maximum time allowance and provides for seasonal variations in operations and work load. The Protection System Maintenance and Testing Reliability Standard (i.e., PRC-005) is based on recurring activities over longer periods than the draft PRC-004-3 Reliability Standard, which is event driven. No change made.
Manitoba Hydro	R6 -when is a change to a CAP considered failure to implement and therefore a violation of R6 (since R6 both requires implementation of a CAP and allows changes to the CAP) **Response:** The drafting team contends that modifying a CAP does not constitute a failure to implement a CAP. According to Requirement R6, a failure to update the CAP when actions or timetables change until completed is a failure to implement the CAP. No change made.
Northeast Power Coordinating Council	Regarding Section 5: Background (page 6), additional justification to explain the application of the standard would be beneficial. As indicated in our previous comments, we disagreed with the omission of UVLS while UFLS is included. The SDT’s response indicates that UVLS has not been included in the proposed standard’s Applicability because Misoperations of UVLS relays are being addressed under Project 2008-02 – Undervoltage Load Shedding when modifying Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance. This rationale is not sufficient to justify the inclusion of UFLS but exclusion of UVLS since both need to be assessed and treated the same. Note that the SAR for PRC-022-1 is being revised to include UFLS. We suggest the PRC-004 SDT coordinate with the PRC-022 SDT to apply a consistent approach to addressing Misoperations of UFLS and UVLS.

Organization	Question 4 Comment
	Response: Undervoltage load shedding (UVLS) has not been included in the draft PRC-004-3 Reliability Standard's Applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Adding UVLS in PRC-004-3 at this point would create unforeseen issues with having Requirements in two different Reliability Standards address the same activity. The purpose of the UFLS project is to address an outstanding FERC directive and review PRC-006-1 to determine if any steady state modifications are appropriate (i.e., Paragraph 81 criteria and recommendations of the Independent Expert Review Panel). Specifically, the other project's standard drafting team will revise PRC-006-1 to address the directive included in FERC Order No. 763 and to provide for clear, unambiguous design and documentation requirements for automatic UFLS programs. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard. The drafting team added additional text to the background to explain both UVLS and UFLS. Clarification made. Requirement R1 does not work for the case where manual intervention to operate the BES device was required. Parts 1.1 thru 1.3 are all ANDS. Part 1.3 requires the Interrupting Device to be operated by the Protection System. This conflicts with the idea in Part 1.1 of MANUAL intervention. If an operator manually opens a breaker because the Composite Protection System does not clear a fault then the Protection System could not have operated the interrupting device. Therefore the threshold R1 would not be met and no identification is required even though the Composite Protection System may have failed-to-trip. Suggest Part 1.3 be revised to read: The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation; or manual intervention was required to operate the BES interrupting device because its Protection System failed to operate. **Response:** The drafting team made a clarification to Requirement R1, Part 1.3 that it includes manual intervention. Clarification made.

Organization	Question 4 Comment
	Requirement R1 can be rephrased to provide clarity to the relationship of Parts 1.1 thru 1.3 to R1. Present phrasing has the added phrase, under the following circumstances, following Misoperation where it can ambiguously modify Misoperation. Clearly the intent is to describe the circumstances that a BES device owner has to embark on a process to identify a Misoperation. There are two inputs prior to beginning the process of identification; first the operation of a BES interrupting device occurs and second that the attributes of Parts 1.1 thru 1.3 are met. It would be clearer to place the reference to Parts 1.1 thru 1.3 prior to the word identify. Suggest Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated, and where such operation conforms to Parts 1.1 thru 1.3, shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation. **Response:** The drafting team made the clarification in Requirement R1.
National Grid	Second part of sub-requirement R1.1 “The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate” seems to contradict with sub-requirement R1.3 “The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation”. R1.1 and R1.3 cannot be met at the same time. **Response:** The drafting team made a clarification to Requirement R1, Part 1.3 that it includes manual intervention. Clarification made. An entity which receives notification of the BES interrupting device(s) operation in requirement R3 is allotted between 60 and 120 calendar days. However, the BES interrupting device(s) owner(s) are allotted 120 calendar days. Receiving entity also should be allotted full 120 calendar days counting from the day it receives notification. **Response:** When an entity receives notification of a Protection System operation by the BES interrupting device owner, the Protection System owner is allotted at least 60 calendar days to

Organization	Question 4 Comment
	identify whether it was a Misoperation. A shorter time period is allotted on the basis that the BES interrupting device owner has already performed preliminary work, collaborated with the other owners, and that other owners generally have fewer associated Protection System components. No change made. Requirements R1, R2, and R3 are assuming that an entity will make an attempt to determine the cause(s) of a Misoperation. However, an entity can choose to make no effort until requirement R4 becomes applicable. It is suggested to expand requirements R1, R2, and R3 with the obligation for an entity to make an effort to determine the cause(s) of a Misoperation before requirement R4 takes place. **Response:** Requirements R1 and R3 do not preclude an entity from determining the cause of an identified Misoperation. (Note: Requirement R2 is for notification to others.) Requirement R4 becomes applicable only after a Protection System operation is "identified as a Misoperation" and does not have an identified cause. Requirement R4 is an exception-based Requirement and is only performed when the entity did not identify the cause(s) upon the identification of the Misoperation in either Requirement R1 or R3. No change made.
Public Service Enterprise Group	See the Consideration of Comments document, pp. 76-77. We interpreted that the SDT agreed to our proposed changes to R3; however it was not reflected in this draft. **Response:** The drafting team meant to explain that it revised the Guidelines and Technical Basis to provide a more detailed explanation of the "two full calendar quarters" rather than change the Requirement R4 language to "180 calendar days." No change made.
Texas Reliability Entity	Texas Reliability Entity is voting Negative on this standard due to the concern that the reliable operation of the BES is not ensured by this standard (as written) because the allowable time periods for investigating and correcting are too long and investigative actions are not required before R4. Please consider the following comments and recommendations.

Organization	Question 4 Comment
	1) Recommend changing the allowable time for identification of a Misoperation to 60 days for R1 and R2. The 120 identification period (in R1 and R2) coupled with the additional allowance in R3 of 60 days means a Misoperation may not be determined up to 179 days after the interrupting device operation. The risk to the BES is still undetermined during this time period and actions should be taken to identify if a Misoperation occurred more expeditiously. **Response:** The drafting team concluded that most Protection System reviews would occur soon after a BES interrupting device operation. The 120 calendar days is a maximum time allowance and provides for seasonal variations in operations and work load and the opportunity to identify any Misoperations which were initially missed. No change made. 2) Suggest revising language in Requirements 1 and 3 to include investigative actions: [each entity] “shall perform investigative actions to identify whether its Protection System component(s) caused a Misoperation” The proposed language would clarify the expectation that investigations are on-going prior to R4. As written, the standard conceivably allows for a period of up to 120 days before investigative actions are performed. Although the application guidelines for R4 states that an entity “is expected to use due diligence in taking investigative action(s) to determine the cause(s)...” and that R4 “provides the entity a mechanism to continue its investigative work...” the standard does not require an entity to do investigative work before R4. **Response:** The drafting team contends that some level of investigation will be necessary to identify a Misoperation. Once a Misoperation is identified (without a cause), Requirement R4 becomes in effect. No change made. 3) Recommend changing the performance of investigative actions to at least once every calendar quarter in R4. If a Misoperation is confirmed (through steps taken in R1 – R3) then the risk to the BES continues until such time as a cause is found and can be corrected. The application guidelines state that periodic investigative action minimizes compliance burden and focuses the entity’s efforts on determining cause, Texas Reliability Entity asserts that the time period of at least one investigative action every two full calendar quarters (180 days) is not adequate to protect reliability.

Organization	Question 4 Comment
	Response: The drafting team contends that the periodic action balances the compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. In addition, certain planned investigative actions may require months or years to schedule and complete due to outages and other factors. No change made. 4) In order for R4 to be measurable there should be a stated time horizon (per NERC's Acceptance of a Reliability Standard, Item 7, first bullet). The investigation may end either by identification of the cause of the Misoperation or a declaration that no cause was found. Suggest adding requirement to either determine the cause or make the no cause found declaration within 365 days after interrupting device operation. **Response:** The drafting team contends that listing a defined time limit to complete the requirement would actually decease reliability. It would have the unintended consequence of causing entity to discontinue its investigation. The requirement allows the entity to either determine the cause or conclude its investigation when it is confident that a cause cannot be determined. The Time Horizons are used by Compliance Enforcement Authority in determining penalties and does not impact the timing or measurability of the requirement. No change made. 5) The investigation and CAP timelines (as written) exceed 12 months so the evidence retention period of 12 months is insufficient. Evidence of investigative actions may be disposed of before corrective action is completed; meaning that a full record of an interrupting device operation may not be available for review by the CEA. In addition, the 12 month evidence retention schedules for R5 and R6 mean that an entity may not have any evidence to prove compliance to a CEA during an audit (which can be several years after a Misoperation). **Response:** The drafting team clarified the time periods for retaining evidence is "a minimum of" and also added for Requirements R1-R4. The "development" was revised to "completion" to reflect the intended retention period. Clarification made.

Organization	Question 4 Comment
MRO NERC Standards Review Forum	Thank you for the opportunity to comment.
Nebraska Public Power District	The 1.2 Evidence Retention section states 12 months is the required evidence retention period for the requirements. It also notes that “the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.” I would recommend that the evidence retention be longer since it will be difficult to reproduce audit period evidence if it has been discarded. **Response:** Evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit. The drafting team used NERC guidance in determining the appropriate evidence retention periods. See the document *Background Information on Quality Reviews*, February 7, 2012 (http://www.nerc.com/files/Background_Document_20120207.pdf). No change made. Project 2014-01 Dispersed Generation has noted that PRC-004 needs to be reviewed and updated to direct the industry as to the appropriateness of the BES elements that require misoperation analysis and documentation related to dispersed generation. It is recommended to consider adding these changes rather than issuing multiple versions of this standard unless there is a serious reliability risk with the existing PRC-004 standard. **Response:** The drafting team recognizes that having multiple versions of a Reliability Standard is not ideal; Additionally, it is not practical to implement changes to the draft PRC-004-3 Reliability Standard based on another project when it is in active development. Because of this, the draft PRC-004-3 Reliability Standard must move forward for approval so that other projects can use a final version as a basis for any proposed inclusions or revisions.

Organization	Question 4 Comment
	The Draft 5 Application Guidelines states "The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5." There are concerns that some CAP evaluations including programs for other locations could be open for long periods of time creating significant audit tracking burdens. Is it acceptable in some cases if a CAP for correcting the issue with equipment that misoperated also has an evaluation to only identify other locations that have a similar issue and once other locations are identified the CAP is considered completed and no other audit tracking is required? If this is acceptable this may be beneficial for cases where there is an issue with a large number of similar breakers, relays, communication schemes, potential devices or current transformers that might be widespread on some systems requiring years to replace or update as part of a program or several programs. If the above is not acceptable as the standard is written consider adding a 3rd bullet to R5 to allow a CAP for the specific misoperations and a requirement to identify other locations or allow a declaration that can be used for creating a CAP for other locations that will be considered separately from PRC-004-3. **Response:** Yes, the drafting team believes your approach meets the intent of Requirement R5. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5. Timeframes and actions associated with the execution of the evaluation are outside the scope of the standard. No change made.

Organization	Question 4 Comment
	There are still concerns with including manual intervention as part of R1 since most appear to agree it is rare. Can the SDT provide some thoughts on the best way to guarantee that a manual intervention is duly tracked and provided to the protection departments for review? Perhaps dispatch centers need to have a procedure or process that specifically states “any manual intervention for a failed protection system must be reported to the appropriate protection system owner”. Would this be considered a reasonable process approach to satisfy the requirements of auditors that the proper misoperation procedures are in place? It may be that the manual intervention requirement is better suited to the SPS, UFSL, UVLS or plant shutdown schemes since those schemes are more likely to allow operators time to react rather than having manual intervention a part of all types of system operations as it is in R1. Perhaps there are cases where an operator has taken action for a transmission line fault or issue that did not clear with primary/secondary/breaker failure or backup remote clearing but I am not aware of any of these cases. It may be better to clarify the types of practical manual interventions that are intended to be covered by the standard or remove it and place it in another standard mentioned above with clarification for the most practical cases where this should be tracked to simplify the misoperation process documents utilities would likely need to have in place. There is concern that an auditor will have the latitude to ask how you guarantee that you are aware and tracked all manual interventions for protection system failures that have taken place on your system in the last audit period and this could be difficult to prove. **Response:** The drafting team asserts that manual interventions do not necessarily need to be tracked, but they are a condition for which a Protection System must be reviewed for Misoperation. Since it is such an unusual occurrence, the drafting team would expect the entity to be informed of such an operation. An example of manual intervention is a Generator Owner intervening to trip a unit where the operator believes a Protection System failure to operate has occurred. No change made.

Organization	Question 4 Comment
SERC Protection and Controls Subcommittee	The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers. **Response:** Thank you for your comment.
Omaha Public Power District	The Omaha Public Power District (OPPD) is still concern with the 60-day requirement to develop a Corrective Action Plan (CAP) for an identified misoperation. This timing is not practical, and depending on the time of the year, budget cycle, scope of work, 60 days is not sufficient to obtain funding for CAPs. Also, the first bullet under R5 would require evaluation of the applicability of all CAPs to all BES locations which, depending on the CAP, could be overly burdensome. As worded, a wiring or setting error would require that all wiring and all settings at all BES locations be checked. The evaluation should be limited to CAPs related to scheme logic or relay design deficiencies. OPPD proposes that 180 days (6 months) is a sufficient timeframe to practically develop a CAP addressing both operational and budgetary coordination. **Response:** The drafting team contends that 60 calendar days is an adequate amount of time to develop a high level evaluation. Timeframes associated with the execution of the evaluation are outside the scope of the standard. No change made.
Northeast Utilities	The Unnecessary Trip definitions as written are unclear and seem to indicate that the total compliment of the Composite Protection System. Suggest the following clarifications; Unnecessary Trip - During Fault - An unnecessary operation of any Protection System of a Composite Protection System for a Fault condition on another Element. Unnecessary Trip - Other Than Fault - An unnecessary operation of any Protection System of a Composite Protection System for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.

Organization	Question 4 Comment
	Response: The drafting team added "Composite" to the definition of "Misoperation" for categories 5 and 6 based on comments during the draft 4 posting (e.g., see RFC – Question 1). This was done for consistency within the definition of "Misoperation." No change made.
SPP Standards Review Group	UFLS is mentioned in 4.2.2 of the Applicability Section but there is no mention of UVLS. Should it be included here? **Response:** Undervoltage load shedding (UVLS) has not been included in the proposed PRC-004-3 standard's Applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Adding UVLS in PRC-004-3 at this point would create unforeseen issues with having Requirements in two different standards address the same activity. The purpose of the UFLS project is to address an outstanding FERC directive and review PRC-006-1 to determine if any steady state modifications are appropriate (i.e., Paragraph 81 criteria and recommendations of the Independent Expert Review Panel). Specifically, the other project's standard drafting team will revise PRC-006-1 to address the directive included in FERC Order No. 763 and to provide for clear, unambiguous design and documentation requirements for automatic UFLS programs. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard. The drafting team added additional text to the background to explain both UVLS and UFLS. Clarification made. We would suggest that the drafting team consider incorporating the evaluation of the CAP's applicability mentioned in the first bullet under Requirement R5 into the CAP itself. This falls in line with the second bullet in the Requirement which is included in the CAP and gets the burden of making the evaluation concurrently with the development of the CAP out of the way. The evaluation could delay the completion of the CAP.

Organization	Question 4 Comment
	Response: By definition the CAP consists of actions to remedy a specific problem (i.e., the Protection System Misoperation). Because the CAP is a specific plan, the evaluation is structured as a separate activity. No change made. References to days should be calendar days and they should be hyphenated; for example 30-, 45-, 60-, or 120-calendar days. Similarly, references to months should be treated in the same manner; for example 12-calendar months. **Response:** The use of a hyphen as suggested is not consistent with the NERC style guide. No change made.
PPL NERC Registered Affiliates	We continue to disagree that stating whether or not a Misoperation occurred (per R1) and (under some circumstances) what the cause was (per R3) should be due within 120 days even though identifying the cause may take much longer or may even prove impossible (per R4). That is, the SDT apparently prefers where uncertainty exists to classify events as Misoperations and retract the declaration if later findings show otherwise, while we prefer the present approach of not assuming a Misoperation if evidence to support such a conclusion is lacking. The difficulty foreseen regarding the SDT's approach is that dated evidence is required in M1 that an entity, "identified the Misoperation... within the allotted time period," and in M3 that it, "identified whether its protection System component(s) caused a Misoperation within the allotted time period," while all we may be able to say after 120 days is that we don't know why an event happened. R4 describes what to do in such a situation, but it does not retract the obligation to provide impossible-to-obtain evidence satisfying M1 and M3. **Response:** Requirements R1 and R3 do not require, but do not preclude an entity from determining the cause of an identified Misoperation. (Note: Requirement R2 is for notification to others.) Requirement R4 becomes applicable only after a Protection System operation is "identified as a Misoperation" and has not identified the cause(s). Requirement R4 is an exception and is only

Organization	Question 4 Comment
	performed when the entity did not identify the cause(s) upon the identification of the Misoperation in either Requirement R1 or R3. No change made. **Response:** The requirement does not preclude the entity from using judgment in the classification of the operation if the available evidence is inconclusive. No change made.
JEA	We disagree with the 60 day limit in R5 to develop a CAP and think it should be 180 days. **Response:** The drafting team believes that 60 days is sufficient to develop a CAP including its applicability to other Protection Systems as there is opportunity to update the CAP in Requirement R6 as needed. The drafting team believes that issues such as cost/benefit scenarios, resource coordination, scheduling, and funding procurement can be considered while developing the schedule of the CAP. No change made.
Southern California Edison Company	With respect to Requirement 5 on the Corrective Action Plan requirements, we are concerned that an entity's declaration that no corrective action will be taken without supporting evidence, could leave a system problem unresolved. **Response:** The drafting team contends that each entity when making a declaration will have to explain "why corrective actions are beyond the entity's control or would not improve BES reliability." This is consistent with the Requirement and Measure. No change made. The decision that a Corrective Action Plan is unnecessary, or the development of a Corrective Action Plan, are both complex actions that should be done jointly by respective owners of the composite protection system in a consensus-building manner. The failure to reach consensus on Correction Action Plans can leave the problem unresolved. **Response:** The drafting team contends that the requirements are structured in a manner that each entity that has identified a cause of a Misoperation of its Protection System components must develop a CAP according to Requirement R5. Other entities are required to develop a CAP if they

Organization	Question 4 Comment
	identified that their components caused a Misoperation, unless corrective actions would not improve BES reliability or are beyond the entity's control. If a CAP results in a modification to a Protection System, PRC-001 – System Protection Coordination requires coordination with other owners.
Wolverine Power Supply Cooperative, Inc.	Wolverine's position is that the PRC-005 standard sufficiently covers the maintenance and testing requirements for protection systems. Because of this maintenance performed, it is not necessary to perform a detailed engineering analysis of every BES protection system operation. Wolverine's position is to only perform an engineering review of protection system operations if there is an apparent misoperation, for example, an over reach condition, failure to trip, etc. These are easily identified by transmission operators if only the correct facility cleared. To use a protection system operation to verify if a primary and backup protection system work properly seems to conflict with the requirement in PRC-005, which is written to ensure protection systems are maintained so they work properly. **Response:** The drafting team notes that the NERC State of Reliability, May 2013 states, "Key Finding 4: Protection System Misoperations are a significant contributor to disturbance events and automatic transmission outage severity. Incorrect settings/logic/design errors, relay failures/malfunctions, and communication failures are the three primary factors that result in such Misoperations." No change made.

END OF REPORT