

Consideration of Comments

Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)

The Project 2010-05.1 Drafting Team thanks all commenters who submitted comments on the proposed standard, PRC-004-3. There were 76 sets of comments, including comments from approximately 210 different people from approximately 132 companies representing all 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the 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 Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.¹

Summary of Changes

The PSMSDT made substantive revisions to the previous draft 3 of PRC-004-3 – Protection System Misoperation Identification and Correction Reliability Standard following its previous 30-day formal comment posting of the standard and successive ballot which received 50.60% stakeholder approval. The following narrative is a summary of the substantive revisions made to the proposed draft 4 of the PRC-004-3 standard.

Definitions

Composite Protection System: The SDT is proposing a new definition to support the revisions to the definition of Misoperation.

Misoperation: The SDT made updated occurrences of “composite Protection System” with the newly proposed term of Composite Protection System. Other revisions include removing the uses of “zone,” and most notably updated the category of “Slow Trip – During Fault” to address high-speed performance. The last category of “Unnecessary Trip – Other Than Fault” was modified to be clear that a Protection System operation due to on-site personnel is not a Misoperation.

Purpose

The purpose statement was reorganized to clarify that the standard applies to those Protection Systems for Bulk Electric System Elements.

¹ The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Facilities

The SDT revised the Facilities section of the Applicability to remove exclusions for Special Protection Systems (SPS) and Remedial Action Schemes (RAS). As a general rule, Reliability Standards should address what is applicable, not what is excluded; therefore, SPS and RAS are not referenced in the Applicability. Exclusions concerning non-protective functions embedded within a Protection System and protective functions intended to operate as a control function (e.g., reverse power when removing a generator from service) have been moved to the main Applicability for Facilities to add clarity that these are not applicable as Protection Systems for Bulk Electric System (BES) Elements.

Effective Dates

The effective dates have not materially changed even though the language shows significant modification. This language change is being applied to Reliability Standards that are currently under development. The change is an outcome of NERC working with Canadian authorities to address their specific circumstances. Also, the Effective Date language now incorporates a provision for the Western Interconnection due to identified overlap between the Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation and the proposed continent-wide Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction. The provision is to allot time for the Western Interconnection to modify the Regional Reliability Standard.

Requirement R1

The SDT reorganized Requirement R1 to improve clarity of the required performance, allotted time periods, and a single reliability objective in a Requirement. The main part of the Requirement begins with defining what starts the review of a Misoperation, which is the operation of a BES interrupting device. In replacing the earlier Part 1.1 and its sub-bullets, the responsible entity will perform a review when the criteria (i.e., 1.1, 1.2, and 1.3) are met. The three criteria include when: the BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; the BES interrupting device owner owns all or part of the Protection System component(s); and the BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation. Part 1.2 is now represented in Requirement R4 to investigate the identified Misoperation to determine a cause, if not previously revealed during the initial review of a Misoperation.

There were a significant number of comments from stakeholders about the confusion between the proposed “action plan” and the “Corrective Action Plan” found in previous Requirement R3. To address these comments, the SDT created Requirement R4 to allow an entity to continue its investigation, as needed, only requiring the entity to demonstrate actions taken at least once in every two full calendar quarters toward determining the cause of an identified Misoperation.

Requirement R2

This requirement is essentially unchanged and is now represented in Requirement R5, the development of a Corrective Action Plan (CAP) to address the cause(s) of an identified Misoperation. The SDT made clarifying revisions to pinpoint the Protection System component that caused the Misoperation as being subject to the (CAP). Also, the word “first” was added before “...identifying the cause...” to improve clarity that upon identifying the “first cause” starts the 60 calendar day time period for developing the CAP. Last, the SDT added the clause “...and that no further corrective actions will be taken” to require entities to clearly state that no additional actions are planned to be taken to provide a measurable close to the performance in the declaration. Also, the phrase “would reduce BES reliability” was replaced with “would not improve BES reliability” to align with those conditions where corrective action may not be practical.

Requirement R3

This requirement was removed by the SDT in the current draft as comments revealed the use of “action plan” along with Corrective Action Plan created unnecessary confusion. The proposed Requirement R4 fills this performance by requiring entities to continue its investigative actions in determining a cause of an identified Misoperation.

Requirement R4

This requirement is now Requirement R6 and is essentially the same as the previous Requirement R4, except that “action plan” was removed. Implementation is further clarified that the CAP must be updated when actions or timetables change through completion of the CAP.”

Compliance

The SDT corrected this section to comport with the standard language NERC uses in Reliability Standards. Also, the Evidence Retention section was changed to reduce the minimum time periods that were previously proposed at six years (i.e., the last audit) for all Requirements to 12 calendar months for all Requirements according to the Standard Drafting Guidelines for evidence retention.

VRFs and VSLs

After further review, the SDT lowered the earlier Requirement R4 (implement the CAP) Violation Risk Level (VRF) from High to Medium. This comports with the VRF found in PRC-016-0.1 – Special Protection System Misoperation, Requirement R2 and PRC-022-1 - Under-Voltage Load Shedding Program Performance, Requirement R1.2. See the VRF and VSL Justifications document for additional information.

The Violation Severity Levels were completely rewritten due to the substantive changes made in restructuring the Requirements to meet a single reliability objective in a requirement. The SDT notes that it applied the VSL Guidelines in establishing the VSLs including the incremental differences between each level.

Application Guidelines

The SDT substantially reorganized the Guidelines and Technical Basis section of the Application Guidelines for organization and flow. Section headers were added and reordered as well as creating additional examples for guidance. For instance, the examples for Requirement R5 and R6 mirror one another to demonstrate an example of Corrective Action Plan (CAP) development (R5) and its implementation (R6).

Index to Questions, Comments, and Responses

- 1. **Based on stakeholder input, the drafting team revised the definition of a Misoperation. The categories as well as the introductory sentence of the definition were modified for clarity. The introductory sentence indicates that a Misoperation pertains to ‘the failure of an Element’s composite Protection System to operate as intended.’ Do you agree with the revised definition? If not, please provide specific suggestions for improvement. 17**
- 2. **Requirement R1 was revised to to provide more clarity regarding the responsibilities of the BES interrupting device owner and the Protection System owner (if they are different entities) when a Protection System operation occurs. Do you agree with these changes? If not, please provide specific suggestions for improvement.46**
- 3. **The Measures and VSLs were revised to reflect changes to the requirements. Do you agree with these changes? If not, please provide specific reasons why not and alternative recommendations and justifications..... 86**
- 4. **The drafting team modified the Guidelines and Technical Basis section to provide more supporting discussions, explanations, and examples for the various aspects of the standard. Do you have any specific suggestions for further improvements? 102**
- 5. **If you have any other comments on this Standard that you haven’t already mentioned above, please provide them here: 118**

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	Russel Mountjoy	Midwest Reliability Organization NERC Standards Review Forum (NSRF)	X	X	X	X	X	X		X		
Additional Member		Additional Organization	Region	Segment Selection									
1.	Joeseeph DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6									
2.	Kenneth Goldsmith	Alliant Energy	MRO	4, 8									
3.	Jodi Jensen	Western Area Power Administration	MRO	1, 6									
4.	Terry Harbor	MidAmerican Energy Company	MRO	1, 3, 5, 6									
5.	Mike Brytowski	Great River Energy	MRO										
6.	Scott Nickels	Rochester Public Utilities	MRO	4, 5									
7.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5									
8.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6									
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6									

Group/Individual	Commenter	Organization	Registered Ballot Body Segment																	
			1	2	3	4	5	6	7	8	9	10								
10. Dan Inman	Minnkota Power Cooperative	MRO	1																	
11. Marie Knox	Midwest ISO, Inc	MRO	2																	
12. Lee Kittleson	Otter Tail Power Cooperative	MRO	1, 5																	
13. Scott Bos	Muscatine Power and Water	MRO	1, 3, 5, 6																	
14. Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5																	
2.	Group	Charles Morgan	Colorado Springs Utilities		X		X		X	X										
Additional Member Additional Organization Region Segment Selection																				
1.	Paul Morland	Colorado Spring Utilities	WECC	1																
2.	Warren Rust	Colorado Spring Utilities	WECC	1																
3.	Donald Loftis	Colorado Spring Utilities	WECC	1																
4.	Travis Dorr	Colorado Spring Utilities	WECC	5																
5.	Shannon Fair	Colorado Spring Utilities	WECC	3																
3.	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.	Carmen Agavriolo	Independent Electricity System Operator	NPCC	2																
3.	Greg Campoli	New York Independent System Operator	NPCC	2																
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	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.	Kathleen Goodman	ISO - New England	NPCC	2																
9.	Michael Jones	National Grid	NPCC	1																
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1																
11.	Christina Koncz	PSEG Power LLC	NPCC	5																
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9																
13.	Bruce Metruck	New York Power Authority	NPCC	6																
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5																
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10																
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1																
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1																

Group/Individual	Commenter	Organization	Registered Ballot Body Segment											
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18. David Ramkalawan	Ontario Power Generation, Inc.	NPCC 5												
19. Brian Robinson	Utility Services	NPCC 8												
20. Brian Shanahan	National Grid	NPCC 1												
21. Wayne Sipperly	New York Power Authority	NPCC 5												
22. Donald Weaver	New Brunswick System Operator	NPCC 2												
23. Ben Wu	Orange and Rockland Utilities	NPCC 1												
24. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC 3												
4.	Group	Mary Jo Cooper	Mary Jo Cooper	X		X								
Additional Member		Additional Organization	Region	Segment Selection										
1.	Ken Dize	Salmon River Electric Coop	WECC	1, 2										
2.	Elizabeth Kirkley	City of Lodi	WECC	2										
3.	Angela Kimmey	City of Pasadena	WECC	1, 2										
4.	Sam Rohn	California Pacific Electric Company	WECC	2										
5.	Colin Murphey	City of Ukiah	WECC	2										
6.	Douglas Draeger	Alameda Municipal Power	WECC	2										
5.	Group	Charles Yeung	ISO RTO Council Standards Review Committee		X									
Additional Member		Additional Organization	Region	Segment Selection										
1.	Greg Campoli	NYISO	NPCC	2										
2.	Bill Phillips	MISO	RFC	2										
3.	Steve Myers	ERCOT	ERCOT	2										
4.	Ben Li	IESO	NPCC	2										
5.	Matt Goldberg	ISONE	NPCC	2										
6.	Tom Bowe	PJM	RFC	2										
7.	Ali Miremadi	CAISO	WECC	2										
6.	Group	paul haase	seattle city light	X		X	X	X	X					
Additional Member		Additional Organization	Region	Segment Selection										
1.	pawel krupa	seattle city light	WECC	1										
2.	dana wheelock	seattle city light	WECC	3										
3.	hao li	seattle city light	WECC	4										
4.	mike haynes	seattle city light	WECC	5										

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			1	2	3	4	5	6	7	8	9	10		
5. dennis sismaet	seattle city light	WECC 6												
7.	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team	X	X	X		X	X						
Additional Member Additional Organization Region Segment Selection														
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA										
2.	Robert Rhodes	Southwest Power Poo	SPP	NA										
3.	James Nail	City Of independence, Missouri	SPP	3										
4.	Ken Zellefrow	City Utilities	SPP	1, 4										
5.	David Oswald	Empire District Electric Company	SPP	1										
6.	Cole Brodine	Nebraska Public Power District	MRO	1, 3, 5										
7.	Gordon Heins	Nebraska Public Power District	MRO	1, 3, 5										
8.	Greg Hill	Nebraska Public Power District	MRO	1, 3, 5										
9.	Stephen Wadas	Nebraska Public Power District	MRO	1, 3, 5										
10.	Shawn Jacobs	Oklahoma Gas and Electric Company	SPP	1, 3, 5										
11.	John Hare	Oklahoma Gas and Electric Company	SPP	1, 3, 5										
12.	Mike Sheriff	Oklahoma Gas and Electric Company	SPP	1, 3, 5										
13.	Jamie Strickland	Oklahoma Gas and Electric Company	SPP	1, 3, 5										
14.	Tiffany Lake	Westar Energy, Inc	SPP	1, 3, 5, 6										
15.	Bo Jones	Westar Energy, Kansas Gas and Electric	SPP	1, 3, 5, 6										
16.	Tim Bobb	Westar Energy, Inc	SPP	1, 3, 5, 6										
17.	Lynn Schroeder	Westar Energy, Inc	SPP	1, 3, 5, 6										
18.	Paul Von Hertsenberg	Westar Energy, Inc	SPP	1, 3, 5, 6										
19.	Mahmood Safi	OPPD	MRO	1, 3, 5										
8.	David Thorne	Pepco Holdings Inc & Affiliates	X		X									
Additional Member Additional Organization Region Segment Selection														
1.	Carl Kinsley	Delmarva Power & Light Co	RFC	3										
2.	Alvin Deperw	Pepco Holdings Inc	RFC	1										
9.	Chang Choi	City of Tacoma, Tacoma Public Utilities	X		X	X	X	X						
Additional Member Additional Organization Region Segment Selection														
1.	Travis Metcalfe	Tacoma Public Utilities	WECC	3										
2.	Keith Morisette	Tacoma Public Utilities	WECC	4										

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3.	Chris Mattson	Tacoma Power	WECC	5																																																												
4.	Michael Hill	Tacoma Public Utilities	WECC	6																																																												
10.	Group	Mike Garton	Dominion										X			X		X	X																																													
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4.	Michael Crowley	Virginia Electric and Power Company	SERC 1, 3, 5, 6																																																													
11.	Group	Brandy Spraker	Tennessee Valley Authority										X			X		X	X																																													
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4.	Greg Cecil	Duke Energy	RFC 6																																																													
13.	Group	David Greene	SERC Protection and Controls Subcommittee																																																													
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			1	2	3	4	5	6	7	8	9	10								
2. Phil Winston	Southern Company																			
3. John Miller	Georgia Transmission Co.																			
4. Jay Farrington	PowerSouth																			
5. Charles Fink	Entergy																			
6. Steve Edwards	Dominion																			
7. George Pitts	TVA																			
8. Bridget Coffman	Santee cooper																			
9. Russ Evans	Scana																			
10. David Greene	SERC																			
14. Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X												
Additional Member Additional Organization Region Segment Selection																				
1. Timothy 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	3																	
5. Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4																	
6. Randy Hahn	Ocala Utility Services	FRCC	3																	
15. Group	Ben Engelby	ACES Standard Collaborators							X											
Additional Member Additional Organization Region Segment Selection																				
1. Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5																	
2. Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1																	
3. Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5																	
4. Mark Ringhausen	Old Dominion Electric Cooperative	SERC	3, 4																	
5. Susan Sosbe	Wabash Valley Power Association	RFC	3																	
6. Tom Alban	Buckeye Power, Inc.	RFC	3, 4																	
16. 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	Registered Ballot Body Segment										
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17.	Group	Brent Ingebrigtsen	PPL NERC Registered Entities	X		X		X	X					
Additional Member		Additional Organization		Region Segment Selection										
1.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1										
2.	Annette Bannon	PPL Generation, LLC on behalf of Supply NERC Registered Entities	RFC	5										
3.	Annette Bannon	PPL Generation, LLC on behalf of Supply NERC Registered Entities	WECC	5										
4.	Elizabeth Davis	PPL Energy Plus, LLC	MRO	6										
5.	Elizabeth Davis	PPL Energy Plus, LLC	NPCC	6										
6.	Elizabeth Davis	PPL Energy Plus, LLC	SERC	6										
7.	Elizabeth Davis	PPL Energy Plus, LLC	SPP	6										
8.	Elizabeth Davis	PPL Energy Plus, LLC	RFC	6										
9.	Elizabeth Davis	PPL Energy Plus, LLC	WECC	6										
18.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X					
Additional Member		Additional Organization		Region Segment Selection										
1.	Dean Bender	Technical Svcs	WECC	1										
2.	Dan Goodrich	Technical Operations	WECC	1										
19.	Individual	Ryan Millard	PacifiCorp	X		X		X	X					
20.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X					
21.	Individual	Ed Croft	Operational Compliance	X		X		X						
22.	Individual	Pamela R. Hunter	Southern Company - Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Mississippi Power Company; Gulf Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X					
23.	Individual	Steve Rueckert	Western Electricity Coordinating Council											X
24.	Individual	Greg Froehling	Rayburn Country Electric Cooperative			X								
25.	Individual	John Miller	Georgia Transmission Corp	X										
26.	Individual	Alice Ireland	Xcel Energy	X		X		X	X					
27.	Individual	Michael Moltane	ITC Holdings	X										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment										
				1	2	3	4	5	6	7	8	9	10	
28.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X					
29.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X					
30.	Individual	Patrick Brown	Essential Power, LLC					X						
31.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X					
32.	Individual	Andrew Z. Puztai	American Transmission Company, LLC	X										
33.	Individual	Jack Stamper	Clark Public Utilities	X										
34.	Individual	Melissa Kurtz	US Army Corps of Engineers					X						
35.	Individual	Bill Middaugh	Tri-State G&T	X										
36.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X						
37.	Individual	Joseph DePoorter	Madison Gas and Electric Company			X	X	X	X					
38.	Individual	John Bee	Exelon Corporation and it's affiliates	X		X		X						
39.	Individual	Mike Hirst	Cogentrix Energy Power Management, LLC					X						
40.	Individual	NICOLE BUCKMAN	Atlantic City Electric Company			X								
41.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X	X					
42.	Individual	Jim Cyrulewski	JDRJC Associates LLC								X			
43.	Individual	Thad Ness	American Electric Power	X		X		X	X					
44.	Individual	Anthony Jablonski	ReliabilityFirst											X
45.	Individual	Mary Downey	City of Redding			X	X	X	X					
46.	Individual	Jonathan Meyer	Idaho Power Company	X										
47.	Individual	Bill Fowler	City of Tallahassee			X								
48.	Individual	Scott Berry	Indiana Municipal Power Agency				X							
49.	Individual	Don Jones	Texas Reliability Entity											X
50.	Individual	Wryan Feil	Northeast Utilities	X										
51.	Individual	Jonathan Appelbaum	The United Illuminating Company	X										
52.	Individual	Mark Yerger	Pepco Holdings, Inc Segment 1			X								
53.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment										
				1	2	3	4	5	6	7	8	9	10	
54.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP					X						
55.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X					
56.	Individual	Daniel Duff	Liberty Electric Power LLC					X						
57.	Individual	Joylyn Faust	Consumers Energy			X	X	X						
58.	Individual	Daniela Hammons	CenterPoint Energy	X										
59.	Individual	Kenn Backholm	Public Utility District No. 1 of Snohomish County	X		X	X	X	X					
60.	Individual	Michael Mayer	Delmarva Power & Light Company			X								
61.	Individual	David Jendras	Ameren	X		X		X	X					
62.	Individual	Martin Kaufman	ExxonMobil Research and Engineering	X				X		X				
63.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X							
64.	Individual	Cole Brodine	Nebraska Public Power District	X		X		X						
65.	Individual	Kenneth A Goldsmith	Alliant Energy				X							
66.	Individual	Scott Langston	City of Tallahassee	X										
67.	Individual	Karen Webb	City of Tallahassee - Electric Utility					X						
68.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X							
69.	Individual	Michael Falvo	Independent Electricity System Operator		X									
70.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X										
71.	Individual	Roger Dufresne	Hydro-Québec Procution					X						
72.	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	X		X		X	X					
73.	Individual	Laurie Williams	Public Service Company of New Mexico	X		X								
74.	Individual	Bret Galbraith	Seminole Electric			X	X	X	X					
75.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X					
76.	Individual	E Scott Miller	MEAG	X		X		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 thanks you for your comments and for simplifying the effort in responding to comments by supporting other entities comments and avoiding unnecessary duplication. Please see the commenting entity’s comments for the drafting team’s responses.

Organization	Supporting Comments of "Entity Name"
City of Redding	BANC/SMUD
Illinois Municipal Electric Agency	Florida Municipal Power Agency
Indiana Municipal Power Agency	Florida Municipal Power Agency
JDRJC Associates LLC	Midwest ISO
Lincoln Electric System	MRO NSRF
US Army Corps of Engineers	MRO NSRF
Alliant Energy	MRO NSRF
The United Illuminating Company	Northeast Power Coordinating Council (NPCC)
Atlantic City Electric Company	Pepco Holdings Inc and Affiliates
Delmarva Power & Light Company	Pepco Holdings Inc and Affiliates

Organization	Supporting Comments of "Entity Name"
Pepco Holdings, Inc Segment 1	Pepco Holdings Inc and Affiliates, Segment 1
Western Electricity Coordinating Council	Sacramento Municipal Utility District
Clark Public Utilities	Sacramento Municipal Utility District
MEAG	Southern Company Services - Generation

1. **Based on stakeholder input, the drafting team revised the definition of a Misoperation. The categories as well as the introductory sentence of the definition were modified for clarity. The introductory sentence indicates that a Misoperation pertains to ‘the failure of an Element’s composite Protection System to operate as intended.’ Do you agree with the revised definition? If not, please provide specific suggestions for improvement.**

Summary Consideration:

The following resulted in a revision to the proposed standard. There were approximately 15 comments supported by 44 individuals concerns expressing concern about the “Slow Trip – During Fault” category of the proposed Misoperation definition. Concerns varied and included; a reference to the NERC Transmission Planning (TPL) Reliability Standards which was removed; the need for precise operating times which were clarified in the Application Guidelines; compliance concerns questioning how entities will be measured in this category; and last, what if adequate data was not available to make a determination.

Concerning the use of the phrase “composite Protection System,” there were about four comments representing about 24 individuals requesting clarification which also resulted in a modification to the proposed standard. The drafting team is proposing the new term “Composite Protection System” for inclusion in the *Glossary of Terms used in NERC Reliability Standards*.

The last item that resulted in a change to the proposed standard concerned on-site activities pertaining to the Misoperation definition category, “Unnecessary Trip – Other Than Fault.” This was supported by two minority comments and individuals requesting clarity that an operation due to on-site or activity activities that result in a Protection System operation would not be a Misoperation. The drafting team concurred and made clarifications to this last category.

The following did not result in a change to the proposed standard. Approximately eight comments supported by about 17 individuals were concerned that the proposed definition of Misoperation (or standard) was inferring that entities will be required to install Disturbance Monitoring Equipment (DME). Although useful in determinations (i.e., slow trips), the standard nor definition require the installation of DME which is being addressed by Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018).

One comment supported by about 17 individuals requested that a Reliability Standard Audit Worksheet (RSAW) be posted contemporaneously with the proposed standard and definition of Misoperation. The drafting team anticipates posting a draft PRC-004-3 RSAW so that entities will have an opportunity to consider auditing approaches. Posting is expected mid-way through the draft 4 posting of PRC-004-3.

Last, a minority set of comments from approximately ten individuals concerning the “Slow Trip – During Fault” offered suggestions that were not implemented – in the judgment of the drafting team, these suggestions did not provide improve clarity.

Organization	Yes or No	Question 1 Comment
ACES Standard Collaborators	No	<p>(1) The term “composite” Protection System is unclear, used inconsistently and should be defined. Based on the first sentence on Page 14 of the Guidelines and Technical Basis section, it appears that all Protection Systems protecting an Element are intended to be included in composite Protection System. That is any primary, secondary, backup, pilot and non-pilot relay schemes for a given Element would be included in its composite Protection System. If this is the case, we suggest just writing a definition so it will be clear where the term comes from and what the meaning is. However, it is not clear that the term is even needed since the definition of Protection System would already include all of these Protection Systems. The definition includes “Protective relays which respond to electrical quantities.” The inconsistent use of “composite” in the standard documents only creates more questions for the need of the definition. For example, on page 14 of Guidelines and Technical Basis section under the section (1) title, the “overall performance of the Protection System for the Element it is designed to protect” is used. This is understood to be all “protective relays” including secondary, backup, pilot and non-pilot relay schemes. As defined, Protection System includes the plural use of protective relays so all could be included.</p> <p>Response: The use of the term “composite” Protection System is intended to address the fact that the term Protection System by itself does not indicate that it is the complete set of protective relaying for an Element such as any primary, secondary, local backup, and communication-assisted relay systems. The word “composite” used as a modifier to Protection System was developed by the NERC SPCS to indicate the total complement of protection for a system Element (line, bus, transformer, generator, etc). To clarify the usage of the terminology, the drafting team is proposing a definition for “Composite Protection System” and has made corresponding changes where “composite Protection System” occurs in the body of the project documents. Change made.</p> <p>(2) Why does the definition need an introductory sentence? The clarifying statement “any of the following is considered a Misoperation” provides the same outcome. Also, several of the sub-parts of the definition discuss the “overall performance of the</p>

Organization	Yes or No	Question 1 Comment
		<p>Protection System,” so this introductory sentence seems redundant. Instead of adding confusion, we recommend that the drafting team strike the entire introduction sentence of the definition.</p> <p>Response: The introductory sentence provides the essential introduction to the numbered parts. The six categories provide the different categories of a Misoperation which classify a Misoperation in terms of Fault or non-Fault conditions, and security or dependability. No change made.</p> <p>(3) For sub-part “3. Slow Trip - During Fault” of the definition, we recommend revising the second sentence. It is a run-on sentence, uses incorrect grammar, contains a triple negative statement, and is confusing. We recommend revising the sentence to clearly state when delayed fault clearing should be excluded and what conditions must be met before the operation is not to be considered a Misoperation.</p> <p>Response: The drafting team agrees and is proposing a revision of “Slow Trip - During Fault” to address this comment and others. Change made.</p> <p>(4) For sub-part “5. Unnecessary Trip - During Fault” of the definition, we believe that the revised sentence now overlaps other sub-parts of the definition. “A Protection System operation for a Fault for which the Protection System is not intended to operate” is almost the exact definition of Misoperation in the introductory sentence. Nothing in this sub-part discusses an unnecessary trip. The phrase “not intended to operate” could apply to all of the other sub-parts because a failure to trip, slow trip, or unnecessary to trip would be the result of a Protection System not operating the way it was intended. More detail is needed for this sub-part.</p> <p>Response: The drafting team agrees and is proposing a revision of “Unnecessary Trip – During Fault” to make clear that this part is for an unnecessary operation for a Fault on another Element. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		

Organization	Yes or No	Question 1 Comment
Xcel Energy	No	<p>a. (This is the single issue causing us to vote negative.) Many generating units with legacy electromechanical protective relay based protection systems do not have DME for high-speed recording of relay-operation events. Although the generating circuit breakers may be on the HV side of GSU transformers and may be monitored via the associated substation DME, the initiating signals from protective relays on the generator side of the GSU may not provide an input or trigger signal to the substation DME. As such, there is little or no value in requiring Generator Owners to try to identify and analyze slow trip events when such data to perform the analysis is not required to be available. In particular, we are concerned that examples provided in the Slow to Trip - Other than Fault bullet of the Misoperation definition (undervoltage, over excitation and loss of excitation) point explicitly toward application of this portion of the definition towards Generator Owners. We are concerned how various auditors may judge entirely qualitative evaluations of the adequacy of GO Protection System performance for Slow to Trip - Other than Fault events when DME is not available, nor required, to quantify performance.</p> <p>Response: The definition and standard do not require the installation of Disturbance Monitoring Equipment (DME); however, the entity must use its available information to determine whether there was a Misoperation. The standard requires all applicable entities to review Protection System operations for Misoperation. Other changes were made to category “4. Slow to Trip - Other than Fault” to identify other conditions for these types of Misoperations and to incorporate the proposed term “Composite Protection System.” Change made.</p> <p>b. Under "Slow Trip - During Fault", is the phrase “Delayed Fault clearing” intended to be the same as the Glossary term “Delayed Fault Clearing”? If not, the similarity of the existing usage with the defined term introduces ambiguity and confusion about intent. Suggest rewording the second sentence under "Slow Trip - During Fault" to eliminate this potential confusion. Note that similar confusion between the term “Delayed Clearing” used in TPL Standards and the Glossary term “Delayed Fault Clearing” resulted in the NERC Interpretation Request 2012-INT-02.</p>

Organization	Yes or No	Question 1 Comment
		<p>Response: The drafting team did not intend “Delayed Fault clearing” to be associated with the NERC glossary definition. The NERC glossary term, “Fault,” was moved to improve the clarity for “Slow Trip – During Fault.” Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
<p>American Electric Power</p>	<p>No</p>	<p>AEP recommends removing the reference to "TPL standards" from the "Slow Trip - During Fault" category of the definition. AEP believes the intent of the "TPL standards" reference can be maintained by capturing all slow trip events that result in clearing more Elements than necessary.</p> <p>Response: The drafting team agrees and has removed the TPL standards reference from “Slow Trip – During Fault.” Change made.</p> <p>AEP's first preference is to reword the category as follows "Slow Trip - During Fault - An Element's composite Protection System operation that, due to the duration of the composite Protection System's operating time, resulted in the clearing of other Elements in addition to the Faulted Element."</p> <p>AEP's second preference is "Slow Trip - During Fault - A composite Protection System operation for the Faulted Element it was designed to protect which was slower than intended. Delayed Fault Clearing due to the non-operation of an installed high-speed protection scheme is not a Misoperation provided the duration of the composite Protection System's operating time did not result in instability or cascading, and did not result in miscoordination with any other composite Protection Systems."</p> <p>Response: The drafting team disagrees with the first suggestion. Remote backup Protection System operation before the Fault is cleared is one indicator of a slow trip. A Composite Protection System that operates slower than required for a Fault on an Element is a Misoperation regardless of whether other Elements operated or not.</p> <p>The drafting team disagrees with the second suggestion because the Composite Protection System must operate as intended (e.g., meet the intended high-speed operation) regardless of whether something bad happened or not. The drafting team</p>

Organization	Yes or No	Question 1 Comment
		<p>made other clarifying changes to the definition of Misoperation. Change made.</p> <p>AEP recommends adding to both “Failure to Trip - During Fault” and “Failure to Trip - other than Fault” - “Please see Category 3(4) to determine if the “slow trip” classification applies to the operation.”</p> <p>Response: The drafting team does not agree that adding references to category 3 (or 4) at the end of category 1 (or 2) is needed. These same types of references could apply elsewhere in the definition and only complicate the definition. No change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
Lincoln Electric System	No	<p>Although supportive of the proposed revisions to the definition of Misoperation, LES is concerned that the phrase “slower than intended” within the definition of a “Slow Trip - During Fault” may lead to unnecessary administrative work in an effort to prove what is considered an acceptable operation time for each Protection System. To avoid requiring entities to develop documentation stating “how fast is fast enough”, recommend modifying the Application Guidelines as follows:</p> <p>(3) ...The phrase “slower than intended” means the Protection System operated slower than the objective of the owner(s).</p> <p>It would be impossible to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System operation was adequate. [The intent is not to require documentation of adequate Protection System operation times, but to assure consideration by the owner(s) reviewing each Protection System operation.]</p>
<p>Response: The drafting team thanks you for your comments and agrees with your sentiment and will add an extra sentence in the paragraph noted in the Application Guidelines regarding the intent. Also, the part of the definition “Slow Trip – During Fault” has</p>		

Organization	Yes or No	Question 1 Comment
been revised to improve clarity. Change made.		
Florida Municipal Power Agency	No	<p>FMPA appreciates the response to our comments, but, we do not believe our issues have been resolved.</p> <p>First, on “Slow Trip”; however, we disagree with your perspective. The SDT is taking a relativistic approach to time, e.g., interpreting the words it drafted “slower than intended” as relating to whether the Protection System operated “fast enough to prevent additional harm” and not a more common interpretation of it operated slower than it was designed to operate. FMPA believes that an auditor would interpret this using the latter interpretation and instead ask for the design clearing time of the protection system as a comparison of whether actual operation was “slow”, e.g., if the system is designed to operate in 5 or 6 cycles and instead it operates in 7 or 8 cycles, fast enough to prevent backup protection from operating, but slower than designed, is that slow? If the SDT intends “slower than intended” to mean that it operates “fast enough to prevent any additional harm”, e.g., the clearing time of the back-up protection, then state that in the definition. The response to our comment (and the Application Guidelines) focuses on the owner of the Protection System “should have an understanding of the objectives of its Protection Systems”; that is not FMPA’s concern. FMPA’s concern is how an auditor will audit R1 and verify that the entity identified all misoperations, and how an auditor will interpret “slower than intended”.</p> <p>Response: The phrase “slower than required” means the Composite Protection System operated slower than the objective of the owner(s). It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation was adequate. The intent is not to require documentation of exact Protection System operation times; however, each entity must determine what evidence it needs to support compliance with the requirements. The definition of Misoperation has been revised to clarify slow trips and additional detail added to the Application Guidelines.</p>

Organization	Yes or No	Question 1 Comment
		<p>Change made.</p> <p>Second, FMPA commented last time (commenting on R1) on the difficulty of measuring whether a fault actually occurred and where the fault in regards to the definitions of “Failure to Trip” and “Unnecessary Trip”. For both, an auditable investigation would need to determine if:</p> <ol style="list-style-type: none"> 1) a fault actually existed, which can be quite difficult to verify for something like a lightning strike with automatic reclosing; and 2) where the fault was; so that it can be determined whether or not the fault was “within the zone it was designed to protect”. <p>In investigating tripping of BES Elements, a large number of those events are indeterminant, meaning that physical evidence could not be found. With microprocessor based protection systems, it may be possible to set up a sort of event recording function that may be able to provide evidence of fault condition and roughly where a fault was; however, with electromechanical relays, that is not possible without installing additional equipment.</p> <p>Is the SDT intending to require a form of event recording at each substation so that the existence and location of a fault can be determined for every protection system trip? If no evidence of a fault exists, would the default assumption be that everything operated as intended unless the evidence of protection system operation indicated otherwise (e.g., both primary and backup systems operated)? If that is the intent, then that intent should be stated within the requirements.</p> <p>Response: Although it is true that it may be difficult to precisely locate a Fault, it is incorrect to consider that these events are indeterminate. As proposed in the PRC-004-3 standard, an entity is not required to precisely locate or find residual evidence of Faults nor is an entity required to install Disturbance Monitoring Equipment (DME). See Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018) for requirements concerning DME. An entity should review the documentation it can obtain for an event, and if there is no evidence of a Misoperation, then the entity could</p>

Organization	Yes or No	Question 1 Comment
		<p>document the operation was correct. No change made.</p> <p>Third, how would a high impedance fault be treated? Such a fault could occur within the relay reach, but, the impedance of the fault could in essence cause the fault to appear further away than it actually is. For instance, assume a line is protected by an instantaneous ground overcurrent relay protecting about 70% of the line and by an inverse time ground overcurrent relay as local backup. And let's say a high impedance fault occurs 50% of the length of the line, but the impedance of the fault reduced the fault current to below the instantaneous relay setting such that the inverse time ground overcurrent relay operates instead. Is that a misoperation because the instantaneous ground overcurrent relay failed to operate for a "Fault within the zone it was designed to protect"?</p> <p>Which leads to the ambiguity of the phrase "within the zone it was designed to protect". Does zone mean a distance as derived from the relay settings, or is it the relay settings themselves? If it is the relay settings themselves, then FMPA suggests changing the phrase to eliminate "zone" and instead refer to the actual protection system settings.</p> <p>Response: The example provided would not be a Misoperation simply because the instantaneous element in the relay did not operate. The drafting team has removed the reference(s) to "zone" in the proposed definition of Misoperation. Change made.</p> <p>Fourth, FMPA is also concerned about how "composite Protection Systems" works, especially with the combination of "within the zone it was designed to protect". For instance, let's assume Line 1 has typical stepped distance scheme of zones, 1 through 3, and let's assume the adjacent Line 2 has a fault and there is a failed breaker at the intermediate substation. The breaker is not part of any protection system, but, the zone 3 remote backup relay of Line 1 operates to help clear the fault on Line 2, which is a correct operation. So, is Line 1's zone 3 relay part of Line 1's composite Protection System, and if so, then there is not a single "zone" for composite Protection Systems, which again adds to the ambiguity of the phrase "within the zone it is designed to protect".</p>

Organization	Yes or No	Question 1 Comment
		<p>Response: Line 1’s zone 3 is a backup relay element that covers Line 1’s primary zone of protection and provides remote protection for other zones. In the example cited, the zone 3 operation is not a Misoperation because it provided proper backup for Line 2 and its zone of protection extends into Line 2. The prior use of the phrase “composite Protection System” was intended to indicate that the collective operations of the entire Protection Systems for an Element that determines whether a Misoperation occurred. To clarify the usage of the phrase, the drafting team is proposing a definition for “Composite Protection System.” Change made.</p> <p>Fifth, some misoperations are due to mistakes made by protection engineers, e.g., mistakes in establishing relay settings; so does: “within the zone it was designed to protect” the actual design of the protection engineer, e.g., the mistaken relay setting, or what the design should have been? If the latter, how will the ‘what the design should have been’ be determined? If the SDT has not already done so, FMPPA recommends involving NERC and RE enforcement staff to discuss how R1 would be audited in combination with these definitions.</p> <p>Response: “Within the zone it was designed to protect” referred to the intended design. The entity must determine and know the intended zone of protection. The drafting team has removed the reference(s) to “zone” in the proposed definition of Misoperation. An incorrect design is a valid cause of a Misoperation. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
Liberty Electric Power LLC	No	<p>I agree with the position of the Standards Development Team of the North American Generator Forum, which states:</p> <p>The topic of slow trips should be removed from PRC-004-3 and the proposed re-definition of a Misoperation, for the following reasons:</p> <ul style="list-style-type: none"> - The standard incorrectly assumes that every NERC-registered generation unit is required to have DME for high-speed recording of relay-operation events. - Where DME is present it is generally installed on the HV side of a unit, and may

Organization	Yes or No	Question 1 Comment
		<p>therefore not yield any useful information for problems occurring at the generator or other low-side components.</p> <ul style="list-style-type: none"> - The standard incorrectly assumes that all GOs have, or should have, design-level relay personnel, ref. the Application Guidelines statements regarding being able to decide whether the speed of the Protection System was adequate (pp. 15 and 16). - Independent GOs in particular have finite resources, and mandating an unreasonable focus on Protection System event record-keeping and analysis will leave other operation and maintenance tasks that much less well covered, resulting in a negative impact on reliability.
<p>Response: The drafting team thanks you for your comments. The slow trip category is included because it is a type of Misoperation which should be identified when possible. In cases where the entity does not have access to Disturbance Monitoring Equipment (DME), a slow trip may be revealed by BES instability and tripping of more than then minimum Element(s). The proposed standard does not require the installation of DME which is being addressed by Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018). The proposed standard does not require an entity to have certain personnel and only specifies the performance required for Misoperation identification and correction. Entities with Protection Systems that are applicable to the standard are required to identify any Misoperation, determine its cause(s), and correct the cause(s) to prevent future occurrences.</p> <p>The standard does, however, require entities to determine if Protection System operations were correct or were Misoperations. Misoperations should be investigated and the causes of those Misoperations should be corrected. To consider if a slow trip Misoperation occurred, the entity must determine if the Protection System operation resulted (due to the operating time) in either the operation of other Elements, instability, or slower than required for a Fault condition for which it was designed. The categories of the definition that are associated with slow trips have been modified to help identify the conditions for these types of Misoperations. No change made.</p>		
Rayburn Country Electric Cooperative	No	<p>I suggest using the word “entire” versus “composite” for clarity sake. composite (adj) Merriam Webster of or relating to a very large family entire (adj) Merriam Webster having no element or part left out ELEMENT NERC Glossary Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be</p>

Organization	Yes or No	Question 1 Comment
		comprised of one or more components.
<p>Response: The drafting team thanks you for your suggestion. The drafting team is proposing a definition for the term “Composite Protection System.” Change made.</p>		
Ingleside Cogeneration LP	No	<p>Ingleside Cogeneration believes that the latest version of the definition correctly captures the intent that the action of the composite Protection System is the gating factor in the determination of a Misoperation. The aggregate action of the primary, secondary, and pilot systems should form the basis of the expected performance, not each individual group of components.</p> <p>However, we still believe that the project team’s intent to allow Protection System owners some flexibility to determine when a “slow trip” occurs is not captured. We fully agree with your statement in the last Consideration of Comments that it is up to the owners to have “an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent any additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate.” However, unless the language is captured in the standard or the definition, CEAs may choose a different basis. In the extreme, they may determine that any delay outside the settings or manufacturer’s specifications to be a Misoperation - even if reliability is not threatened or monitoring equipment cannot resolve down to that level of granularity.</p>
<p>Response: The drafting team thanks you for your comments and cannot speak to the approach that might be used by the Compliance Enforcement Authority (CEA). Based on the Requirements and definition of Misoperation, an entity must identify any Misoperation according to the information available at the time. The drafting team is proposing a definition for “Composite Protection System.” The categories of the definition that are associated with slow trips have been revised to identify the other conditions for these types of Misoperations. No change made.</p>		
Independent Electricity System Operator	No	<p>NPCC uses different terms, such as failure to operate (not operating when required) vs misoperation (operating when not required). We think that the definition here has the intention of defining more generally an "incorrect operation", and perhaps the</p>

Organization	Yes or No	Question 1 Comment
		"incorrect operation" should be used for both different terms.
<p>Response: The drafting team thanks you for your comments. The defined term “Misoperation” in the <i>Glossary of Terms used in NERC Reliability Standards</i> covers Protection System security and dependability failures. The proposed Misoperation definition revision is intended to provide additional clarity. No change made.</p>		
PacifiCorp	No	<p>PacifiCorp believes that the definition used for a Slow Trip During Fault misoperation on Page 4 should be amended to provide more clarity. The current definition reads as follows:</p> <p>“Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance has not been identified to meet the dynamic stability performance requirements of the TPL standards nor is it required to ensure coordination with other Protection Systems.”</p> <p>PacifiCorp suggests changing “identified to meet” to “identified as necessary to meet.”</p>
<p>Response: The drafting team thanks you for your comments and has revised the “Slow Trip - During Fault” category of the proposed Misoperation definition to incorporate this suggestion. Change made.</p>		
City of Tallahassee	No	<p>Some of the scenerios for possible mis-operations are too vague. For example what constitutes a slow trip and what would constitute how a protection system is designed? If a protection scheme is designed to trip in 2-3 cycles and it trips in 5-6 cycles yet still protects the equipment, an auditor could see that as a mis-operation however it still would protect the equipment as it was designed.</p> <p>Response: If the Protection System operates slower than required on the Element(s) it is designed to protect or the Protection System operates slower than what was previously identified as being necessary to prevent voltage or dynamic instability, then it is a “Slow Trip” Misoperation. Your example would not be a Misoperation unless it resulted in an over-trip or instability. No change made.</p> <p>Also, it can be difficult at times to determine if a fault actually occurred within a relay’s</p>

Organization	Yes or No	Question 1 Comment
		<p>zone of reach. If a bolt of lightning causes a fault on a line unless there is physical damage there can be little visual indication of a fault. It can be difficult to confirm if a mis-operation occurred if you can not first confirm what caused the fault.</p> <p>Response: Although it is true that it may be difficult to precisely locate a Fault, it is incorrect to consider that these events are indeterminate. As proposed in the PRC-004-3 standard, an entity is not required to precisely locate or find residual evidence of Faults nor is an entity required to install Disturbance Monitoring Equipment (DME). See Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018) for requirements concerning DME. An entity should review the evidence it can obtain for an event, and if there is no evidence of a Misoperation, then the entity could document the operation was correct. No change made. No change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
City of Tallahassee	No	<p>Some of the scenerios for possible mis-operations are too vague. For example what constitutes a slow trip and what would constitute how a protection system is designed? If a protection scheme is designed to trip in 2-3 cycles and it trips in 5-6 cycles yet still protects the equipment, an auditor could see that as a mis-operation however it still would protect the equipment as it was designed.</p> <p>Response: If the Protection System operates slower than required on the Element(s) it is designed to protect or the Protection System operates slower than what was previously identified as being necessary to prevent voltage or dynamic instability, then it is a “Slow Trip” Misoperation. Your example would not be a Misoperation unless it resulted in an over-trip or instability. No change made.</p> <p>Also, it can be difficult at times to determine if a fault actually occurred within a relay’s zone of reach. If a bolt of lightning causes a fault on a line unless there is physical damage there can be little visual indication of a fault. It can be difficult to confirm if a mis-operation occurred if you can not first confirm what caused the fault.</p> <p>Response: Although it is true that it may be difficult to precisely locate a Fault, it is</p>

Organization	Yes or No	Question 1 Comment
		<p>incorrect to consider that these events are indeterminate. As proposed in the PRC-004-3 standard, an entity is not required to precisely locate or find residual evidence of Faults nor is an entity required to install Disturbance Monitoring Equipment (DME). See Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018) for requirements concerning DME. An entity should review the evidence it can obtain for an event, and if there is no evidence of a Misoperation, then the entity could document the operation was correct. No change made. No change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
<p>City of Tallahassee - Electric Utility</p>	<p>No</p>	<p>Some of the scenerios for possible mis-operations are too vague. For example what constitutes a slow trip and what would constitute how a protection system is designed? If a protection scheme is designed to trip in 2-3 cycles and it trips in 5-6 cycles yet still protects the equipment, an auditor could see that as a mis-operation however it still would protect the equipment as it was designed.</p> <p>Response: If the Protection System operates slower than required on the Element(s) it is designed to protect or the Protection System operates slower than what was previously identified as being necessary to prevent voltage or dynamic instability, then it is a “Slow Trip” Misoperation. Your example would not be a Misoperation unless it resulted in an over-trip or instability. No change made.</p> <p>Also, it can be difficult at times to determine if a fault actually occurred within a relay’s zone of reach. If a bolt of lightning causes a fault on a line unless there is physical damage there can be little visual indication of a fault. It can be difficult to confirm if a mis-operation occurred if you can not first confirm what caused the fault.</p> <p>Response: Although it is true that it may be difficult to precisely locate a Fault, it is incorrect to consider that these events are indeterminate. As proposed in the PRC-004-3 standard, an entity is not required to precisely locate or find residual evidence of Faults nor is an entity required to install Disturbance Monitoring Equipment (DME). See Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018) for requirements concerning DME. An entity should review the evidence it can obtain for</p>

Organization	Yes or No	Question 1 Comment
		an event, and if there is no evidence of a Misoperation, then the entity could document the operation was correct. No change made. No change made.
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
Entergy Services, Inc. (Transmission)	No	Suggest Misoperation definition #6 be revised from “unrelated to on-site maintenance....” to “unrelated to maintenance....” to clearly allow as an exclusion, a Protection System maintenance or commissioning activity which results in an inadvertent remote end station trip. For example, a direct transfer trip scheme.
<p>Response: The drafting team thanks you for your comments. It is important to emphasize that the maintenance exclusion is for active maintenance. A remote-end trip is included in the existing exclusion if it resulted from “on-site” activities at a different location. The Application Guidelines have also been enhanced with an example (6d) related to this topic. Change made.</p>		
Dominion	No	The addition of the word “composite” adds nothing to the existing term Protection System and in fact introduces confusion. Dominion assumes a Misoperation occurs only if all protection (primary, secondary, backup, pilot and non-pilot relay schemes) failed to operate as intended. If this assumption is incorrect, please clarify.
<p>Response: The drafting team thanks you for your comments. The composite Protection System is the collective operation of the entire Protection System for an Element which is included in determining whether a Misoperation occurred. To clarify the usage of the terminology, the drafting team is proposing the definition “Composite Protection System” which has an exclusion for backup protection provided by a remote Protection System. Change made.</p>		
Midwest Reliability Organization NERC Standards Review Forum (NSRF)	No	The NSRF would like to see a RSAW for this particular standard to better understand what level of review and or evidence, if any, auditors will require to determine that you assessed your operations adequately for R1. For instance if you didn’t have certain monitoring equipment that captures data for protection system elements, then the data available would be limited for assessing slow trips.
<p>Response: The drafting team thanks you for your comments. The drafting team anticipates posting a draft PRC-004-3 RSAW so that</p>		

Organization	Yes or No	Question 1 Comment
<p>entities will have an opportunity to consider auditing approaches. Posting is expected mid-way through the draft 4 posting of PRC-004-3. No change made.</p>		
<p>Tennessee Valley Authority</p>	<p>No</p>	<p>The proposed Misoperation definition is based on the “Protection System” definition defined in the NERC Glossary of Terms (GoT). However, the NERC GoT does not provide the elements that are considered “Protective System” elements. The actual descriptions of the “Protection System” elements are found in PRC-005-2, 4.2 Facilities.</p> <p>Recommend this PRC-004-3 revision include a new GoT definition of “Protective System Element” based on PRC-005-2, 4.2, Facilities, or a revision to the NERC GoT to include an abbreviated summary of the PRC-005, 4.2, Facilities in the “Protection System” definition; or include an abbreviated summary of the PRC-005-2, 4.2 Facilities into the PRC-004-3 definition of “Misoperations;” or revise both the NER GoT definition of “Protection System”, and PRC-004-3 definition of “Misoperation” to reference PRC-005, 4.2, Facilities, as the elements that are “Protection System elements.”</p>
<p>Response: The drafting team thanks you for your comments. The composite Protection System is the collective operation of the entire Protection System for an Element which is included in determining whether a Misoperation occurred. To clarify the usage of the terminology, the drafting team is proposing the definition “Composite Protection System” which has an exclusion for backup protection provided by a remote Protection System. Change made.</p>		
<p>Duke Energy</p>	<p>No</p>	<p>The revised definition still contains the incorrect reference to TPL standards in “Slow Trip - During Fault”. The TPL standards Category A, B and C do not require Planning to identify every place where high speed protection is required for dynamic stability. If a Category B issue is identified, high speed protection is installed and it is no longer on the Category B list. If a Category C issue is identified, a redundant relay scheme is installed and it is no longer a Category C issue. Therefore, the list of places where “high-speed performance has been identified to meet the dynamic stability performance requirements of the TPL standards” is just a list of where the appropriate corrective action has not yet been implemented and could, in theory, be empty.</p>

Organization	Yes or No	Question 1 Comment
		<p>“Slow Trip - During Fault” should be revised as follows: “A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance has not been identified as needed by the Planning Authority or the Transmission Operator, or if it is not required to ensure coordination with other Protection Systems.”</p>
<p>Response: The drafting team thanks you for your comments. The reference to the TPL standards in both the Misoperation definition and body of the standard has been removed. Change made.</p>		
ReliabilityFirst	No	<p>The revision to part three of the definition that converted the original parenthetical example into an exclusion by stating it inversely creates a potential loophole. The revised wording would consider correct the slow operation of a Protection System that caused avoidable equipment damage (due to the delayed fault clearing) as long as it did not cause a dynamic stability or coordination issue.</p> <p>The Protection System also needs to coordinate with the damage curves of the equipment within its zone. As the exclusionary sentence stands, it actually uses double negatives. It would be better to restate the sentence positively. A suggested improvement would to replace the second sentence in part three of the definition with the following: Delayed Fault clearing associated with an installed high-speed protection scheme is an example of a Misoperation if high-speed performance is required to meet the dynamic stability performance of the TPL standards or is required to ensure coordination with other Protection Systems.</p>
<p>Response: The drafting team thanks you for your comments and has modified the “Slow Trip - During Fault” category of the Misoperation definition. Change made.</p>		
Texas Reliability Entity	No	<p>The SDT may want to consider adding loadability as an example under “Failure to Trip - Other Than Fault” and under “Unnecessary Trip - Other Than Fault”.</p> <p>Response: It would be incorrect to add loadability as an example under “Failure to Trip</p>

Organization	Yes or No	Question 1 Comment
		<p>– Other than Fault” as normally there would not be a need to trip under load. There are no inclusion examples under “Unnecessary Trip - Other Than Fault” as this category could include a broad range of conditions including normal conditions. The examples in this category are exclusionary and loadability is not a case that should be excluded. No Change made.</p> <p>The existing definition of the ‘Slow Trip-During Fault’ needs to include that the delayed fault clearing associated with the installed high-speed performance of the protection system is not required to meet the voltage ride-through capabilities of the generators. Generators should not be tripping off line due to suppressed voltage in the system stemming from the delayed fault clearing. This could create steady state voltage issues. Suggested language:</p> <p>"Slow Trip - During Fault - A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. (Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance has not been identified to meet the dynamic stability performance requirements of the TPL standards nor is it required to ensure coordination with other Protection Systems ***or result in loss of generation due to delayed fault clearing time***."</p> <p>Also, the definition of “Slow Trip - During Fault” refers to stability performance requirements of the TPL Standards, however, the TPL Standards do not cover delayed three-phase fault clearing studies. Delayed three-phase fault clearing can create undesired system conditions.</p> <p>Response: The suggested condition, loss of generation due to delayed fault clearing time, is a specific class of coordination issues which are included in the “Slow Trip - During Fault” part of the Misoperation definition. “Slow Trip - During Fault” has been revised and the reference to the TPL standards has been removed. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		

Organization	Yes or No	Question 1 Comment
Cogentrix Energy Power Management, LLC	No	<p>The topic of slow trips should be removed from PRC-004-3 and the proposed re-definition of a Misoperation, for the following reasons:</p> <ul style="list-style-type: none"> - The standard incorrectly assumes that every NERC-registered generation unit is required to have DME for high-speed recording of relay-operation events. - Where DME is present it is generally installed on the HV side of a unit, and may therefore not yield any useful information for problems occurring at the generator or other low-side components. - The standard incorrectly assumes that all GOs have, or should have, design-level relay personnel, ref. the Application Guidelines statements regarding being able to decide whether the speed of the Protection System was adequate (pp. 15 and 16). - Independent GOs in particular have finite resources, and mandating an unreasonable focus on Protection System event record-keeping and analysis will leave other operation and maintenance tasks that much less well covered, resulting in a negative impact on reliability.
<p>Response: The drafting team thanks you for your comments. The slow trip category is included because it is a type of Misoperation which should be identified when possible. In cases where the entity does not have access to Disturbance Monitoring Equipment (DME), a slow trip may be revealed by BES instability and tripping of more than then minimum Element(s). The proposed standard does not require the installation of DME which is being addressed by Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018). The proposed standard does not require an entity to have certain personnel and only specifies the performance required for Misoperation identification and correction. Entities with Protection Systems that are applicable to the standard are required to identify any Misoperation, determine its cause(s), and correct the cause(s) to prevent future occurrences.</p> <p>The standard does, however, require entities to determine if Protection System operations were correct or were Misoperations. Misoperations should be investigated and the causes of those Misoperations should be corrected. To consider if a slow trip Misoperation occurred, the entity must determine if the Protection System operation resulted (due to the operating time) in either the operation of other Elements or instability, or slower than required for a Fault condition for which it was designed. The categories of the definition that are associated with slow trips have been modified to help identify the conditions for these types of Misoperations. No change made.</p>		

Organization	Yes or No	Question 1 Comment
PPL NERC Registered Entities	No	<p>The topic of slow trips should be removed from PRC-004-3 and the proposed re-definition of a Misoperation, for the following reasons:</p> <ul style="list-style-type: none"> o The standard incorrectly assumes that every NERC-registered generation unit is required to have DME for high-speed recording of relay-operation events. o Where DME is present it is generally installed on the HV side of a unit, and may therefore not yield any useful information for problems occurring at the generator or other low-side components. o The standard incorrectly assumes that all GOs have, or should have, design-level relay personnel, ref. the Application Guidelines statements regarding being able to decide whether the speed of the Protection System was adequate (pp. 15 and 16). o Independent GOs in particular have finite resources, and mandating an unreasonable focus on Protection System event record-keeping and analysis will leave other operation and maintenance tasks that much less well covered, resulting in a negative impact on reliability.
<p>Response: The drafting team thanks you for your comments. The slow trip category is included because it is a type of Misoperation which should be identified when possible. In cases where the entity does not have access to Disturbance Monitoring Equipment (DME), a slow trip may be revealed by BES instability and tripping of more than then minimum Element(s). The proposed standard does not require the installation of DME which is being addressed by Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018). The proposed standard does not require an entity to have certain personnel and only specifies the performance required for Misoperation identification and correction. Entities with Protection Systems that are applicable to the standard are required to identify any Misoperation, determine its cause(s), and correct the cause(s) to prevent future occurrences. No change made.</p>		
Essential Power, LLC	No	<p>The topic of slow trips should be removed from PRC-004-3 and the proposed re-definition of a Misoperation, for the following reasons:</p> <ul style="list-style-type: none"> -The standard incorrectly assumes that every NERC-registered generation unit is required to have DME for high-speed recording of relay-operation events. -Where DME is present it is generally installed on the HV side of a unit, and may

Organization	Yes or No	Question 1 Comment
		<p>therefore not yield any useful information for problems occurring at the generator or other low-side components.</p> <p>-The standard incorrectly assumes that all GOs have, or should have, design-level relay personnel, ref. the Application Guidelines statements regarding being able to decide whether the speed of the Protection System was adequate (pp. 15 and 16).</p> <p>-Independent GOs in particular have finite resources, and mandating an unreasonable focus on Protection System event record-keeping and analysis will leave other operation and maintenance tasks that much less well covered, resulting in a negative impact on reliability.</p>
<p>Response: The drafting team thanks you for your comments. The slow trip category is included because it is a type of Misoperation which should be identified when possible. In cases where the entity does not have access to Disturbance Monitoring Equipment (DME), a slow trip may be revealed by BES instability and tripping of more than then minimum Element(s). The proposed standard does not require the installation of DME which is being addressed by Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018). The proposed standard does not require an entity to have certain personnel and only specifies the performance required for Misoperation identification and correction. Entities with Protection Systems that are applicable to the standard are required to identify any Misoperation, determine its cause(s), and correct the cause(s) to prevent future occurrences. No change made.</p>		
ExxonMobil Research and Engineering	No	
SERC Protection and Controls Subcommittee	Yes	<p>1) Please revise the Slow Trip - During Fault second sentence for clarity. We suggest: “Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation unless the high-speed performance has either been identified to meet the dynamic stability performance requirements of the TPL standards, or is required to ensure coordination with other Protection Systems.”</p> <p>Response: The “Slow Trip - During Fault” category of the definition has been revised for clarity. Change made.</p> <p>2) We suggest clarifying Definition (6) by replacing "is unrelated to on-site" with "the</p>

Organization	Yes or No	Question 1 Comment
		<p>Protection System that operated is not directly associated with" as shown below to be consistent with page 17, and to exclude transfer trip testing:</p> <p>Unnecessary Trip - Other Than Fault - A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and the Protection System that operated is not directly associated with maintenance, testing, inspection, construction or commissioning activities.</p> <p>Response: Replacing "is unrelated to on-site" in category 6 of the definition removes the implication that these activities were actively being performed. The inadvertent operation of transfer trip during "on-site" activities is excluded from being considered a Misoperation. The Application Guidelines before and after Example 6d has been revised to emphasize this point. Change made.</p> <p>3) Add an Application Guideline example showing that transfer trip testing would not be considered Misoperation as well. Even though the BES interrupting device is at a different location than the testing error, the transfer trip composite system is involved. We suggest:</p> <p>"An operation that occurs during a non-fault condition but was initiated by remote transfer trip system maintenance, testing, inspection, construction or commissioning activities is not a Misoperation."</p> <p>Response: See Example 6d which was added to the Application Guidelines. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
Georgia Transmission Corp	Yes	<p>6. Unnecessary Trip - Other Than Fault: ...is not intended to operate. An Operation caused by on-site maintenance, testing, inspection, construction or commissioning activities on the designated Protection System are not considered as a Misoperation. alternatively: ...is not intended to operate. Operation of a Protection System that is not the focus of on-site maintenance, testing, inspection, construction or commissioning</p>

Organization	Yes or No	Question 1 Comment
		<p>activity is considered a Misoperation.</p> <p>Suggested to highlight the second sentence in the 4th paragraph for definition 6 in the Application Guidelines.</p>
<p>Response: The drafting thanks you for your comments and declines to make the suggested change since it does not add clarity. No change made.</p>		
<p>City of Tacoma, Tacoma Public Utilities</p>	<p>Yes</p>	<p>Is mechanical failure of an interrupting device during a fault a mis-operation? (The interrupting device is not part of the Protection System.)</p> <p>Response: No, a mechanical failure of an interrupting device is not considered a Misoperation since the interrupting device is not part of the Protection System. No change made.</p> <p>Is inappropriate operation of a relay that operates upon mechanical inputs a mis-operation? For example, what if the relay causes a trip when it should have restrained?</p> <p>Response: If the mechanical input is not part of the Protection System it is not a Misoperation. Special Protection Systems (SPS) are not applicable to this Standard. If the mechanical input is part of the Protection System, like an incorrectly set selector switch on a relay, then the operation would be considered a Misoperation. Your example indicates that the mechanical inputs are status points that are used to restrain operation. If these status points are not indicating properly because of a personnel error (e.g., wrong switch position), a problem with a switch, or faulty contacts and a false operation occurs, then it is a Misoperation unless the operation occurred during on-site maintenance. No change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
<p>Southern Company - Southern Company Services, Inc.;</p>	<p>Yes</p>	<p>Southern Company supports the SERC comments and are including the following additional comments:</p>

Organization	Yes or No	Question 1 Comment
Alabama Power Company; Georgia Power Company; Mississippi Power Company; Gulf Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		<p>1. We believe that the same consideration of whether or not the composite Protection System operated as intended could be addressed with a much simpler definition: "The failure of the Protection System to operated as intended, including failing to trip when it should have, unnecessarily tripping with it should not have, or tripping more slowly than intended." This definition allows the Protection System owner to evaluate the operation and determine if it operated appropriately.</p> <p>Response: Although a simpler definition has advantages, it has significant shortfalls. For example, by using the word "when" it is not clear whether an operation is a Misoperation if it was slow or just whether it did or didn't operate. The proposed definition does not achieve the clarity that the specific exceptions in the six categories provide. No change made.</p> <p>2. We believe that the shift in focus to "composite" and "overall performance" does not clarify the ability to identify misoperating Protection System components.</p> <p>Response: The standard proposes a new definition for "Composite Protection System to clarify what is in scope when reviewing Protection System operations. The word "overall" has been removed as it is subjective and not necessary with the inclusion of the proposed Composite Protection System definition. Change made.</p>
Response: The drafting team thanks you for your comments; please see the above responses.		
Colorado Springs Utilities	Yes	
Northeast Power Coordinating Council	Yes	
Mary Jo Cooper	Yes	
ISO RTO Council Standards Review Committee	Yes	

Organization	Yes or No	Question 1 Comment
seattle city light	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
Pepco Holdings Inc & Affiliates	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	
Operational Compliance	Yes	
ITC Holdings	Yes	
Public Service Enterprise Group	Yes	
Manitoba Hydro	Yes	
American Transmission Company, LLC	Yes	
Tri-State G&T	Yes	
Wisconsin Electric Power Company	Yes	

Organization	Yes or No	Question 1 Comment
Madison Gas and Electric Company	Yes	
Exelon Corporation and it's affiliates	Yes	
Sacramento Municipal Utility District	Yes	
Idaho Power Company	Yes	
Northeast Utilities	Yes	
Kansas City Power & Light	Yes	
CenterPoint Energy	Yes	
Public Utility District No. 1 of Snohomish County	Yes	
Ameren	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Nebraska Public Power District	Yes	
Oncor Electric Delivery Company LLC	Yes	
Hydro-Québec Procution	Yes	

Organization	Yes or No	Question 1 Comment
Los Angeles Department of Water and Power	Yes	
Public Service Company of New Mexico	Yes	
City of Austin dba Austin Energy	Yes	
Seminole Electric		<p>The NERC STD defines a Slow Trip as a “Protection System operation that is slower than intended... .” (emphasis added). My preliminary read of this language was that if the Protection System operated slower, i.e., took even 1 cycle longer in time to operate, than how it was intended to be set, that such delay would be a Slow Trip. However, reading your responses to comments, it appears that “time” is not the measure of compliance, but in fact, the compliance metric is based on intended protective objective. By this I mean, if the overall goal of protection is met, then there is no slow trip no matter how much time has passed. To clarify even more, so as long as no additional harm has occurred during the time delay, time is not the measurement for compliance, but harm to the protected equipment is the compliance measure. With that said, can you please describe in some more detail how this compliance metric, i.e., additional harm, will be documented and audited?</p>
<p>Response: The drafting team thanks you for your comments. The slow trip category is included because it is a type of Misoperation which should be identified when possible. In cases where the entity does not have access to Disturbance Monitoring Equipment (DME), a slow trip may be revealed by BES instability and tripping of more than then minimum Element(s). The proposed standard does not require the installation of DME which is being addressed by Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018). No change made.</p> <p>The phrase “slower than required” means the Composite Protection System operated slower than the objective of the owner(s). It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its</p>		

Organization	Yes or No	Question 1 Comment
		Protection System operation was adequate. The intent is not to require documentation of exact Protection System operation times; however, each entity must determine what evidence it needs to support compliance with the requirements. The definition of Misoperation has been revised to clarify slow trips and additional detail added to the Application Guidelines. Change made.

2. ***Requirement R1 was revised to to provide more clarity regarding the responsibilities of the BES interrupting device owner and the Protection System owner (if they are different entities) when a Protection System operation occurs. Do you agree with these changes? If not, please provide specific suggestions for improvement.***

Summary Consideration:

The following resulted in a revision to the proposed standard. This first summary response addresses the majority comment which accounted for at least 16 comments represented by 63 individuals and a change to the proposed standard. Stakeholders raised issues about the lack of clarity concerning who had responsibility under Requirement R1. To resolve this, the drafting team revised Requirement R1 to provide clarity on each Protection System owners' responsibilities following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components, time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation.

Also resulting in a change to the proposed standard, approximately six comments supported by 11 stakeholders had concern about initiating the review for Misoperation based on the operation of the BES interrupting device. The drafting team noted 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). And 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. 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. Requirement R1 was revised to bring clarity to the obligations of each applicable entity.

The drafting team revised the standard based on at least two comments represented by 27 stakeholders that were concerned about working cooperatively when the Protection System is jointly owned. The drafting team clarified that the notification starts the period for the Protection System component owner to begin its investigation. More importantly, having the BES interrupting device owner "officially notifying" other Protection System component owners when there may be no need to do so, will create an unnecessary compliance obligation for the other owners, especially when there is little possibility that another owner's Protection System component(s) caused a Misoperation. The requirements do not preclude the entity that is reviewing the operation from working with the other owners and when necessary, make the official notification. Requirement R1 has been revised to clarify that

the BES interrupting device must make notifications (now R2) when Protection System component(s) did not cause the BES interrupting device(s) operation.

The use of “BES interrupting device” was raised in at least two comments representing 13 stakeholders. The drafting team clarified the use of “BES interrupting device” in the standard’s Application Guidelines under the “Definitions” section.

About five comments supported by individual stakeholders expressed concern about the action plan which resulted in a revision to the proposed standard. The standard now provides the entity a periodic time frame for continuing its investigation into the cause of the Misoperation beyond the 120 calendar day period. This also replaced the previous Requirement for having an “action plan” and is now addressed by Requirement R4.

The phrase “slower than required” means the Composite Protection System operated slower than the objective of the owner(s). It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation was adequate. The intent is not to require documentation of exact Protection System operation times; however, each entity must determine what evidence it needs to support compliance with the requirements. The definition of Misoperation has been revised to clarify slow trips and additional detail added to the Application Guidelines. Change made.

Last, a few comments by stakeholders led to revising the Measures. Only one comment resulted in the drafting team including a suggestion to incorporate the “manual intervention” due to a BES Protection System failure to operate into Requirement R1 to address a failure to trip. The drafting team responded to this single minority comment recognizing that the condition is possible and has adequate merit to be included in the requirement.

The following did not result in a change to the proposed standard. The remaining text summarizes industry concerns that did not result in a change to the proposed standard. Approximately seven comments supported by at least 40 stakeholders were concerned that the standard unnecessarily places entities a risk of a violation should they miss the review period due to natural disasters or some other unusual circumstance. The drafting team responded that 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, including specific language in the proposed standard complicates a low frequency event where a compliance violation might occur and does not benefit the standard overall.

At least one comment representing about eight individuals suggested the standard lean more toward performance objectives to remove ambiguities and judgment concerns (e.g., slow trips). The drafting team continues to support the proposed standard as

currently structured noting that the draft requirements allow Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities.

Another single comment supported by eight stakeholders was concerned about what to do when there is a lack of information to determine whether a Misoperation occurred or not. Although this did not result in a change to the proposed standard, the drafting team noted that an entity should review the documentation it can obtain for an event, and if there is no evidence of a Misoperation, then the entity could judge the operation was correct. No change made.

Two single comments that did not result in a revision to the proposed standard were concerned with how to review Protection System operations. The drafting team responded that the construction of Requirement R1 requires that each operation of a Protection System that causes a BES interrupting device operation must be reviewed to ensure that the Protection System responded correctly. An entity may choose to group operations by event; however, in the case of a single permanent fault caused an initial operation and a subsequent reclose and operation, all operations must be reviewed to determine if the Protection System responded appropriately. This achieves the objectives of the standard in ensuring correct performance of Protection Systems, as well as identifying and correcting the root causes of Misoperations which do affect reliability of the BES.

A single minority comment was concerned about which entity would report for jointly owned Protection Systems where each entity had a Misoperation cause. The NERC Rules of Procedure, Section 1600 Request for Information or Data (i.e., Data Request) specify the Protection System owner that caused the Misoperation will report.

Organization	Yes or No	Question 2 Comment
Kansas City Power & Light	No	R1 and the rationale for R1 assume that the BES interrupting device owner and the Protection System owner have been talking and R1 requires identification and review of each operation within 120 days. R1 should require that the BES interrupting device owner notify the Protection System owner or vice versa, depending on which entity discovers the event first, within a specific time after the entity is aware of the operation in order to ensure that the other entity has adequate time within the 120 day period to finish the review.
<p>Response: The drafting team thanks you for your comment. Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of</p>		

Organization	Yes or No	Question 2 Comment
		<p>the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. The standard now provides the entity an extended period for continuing its investigation of a potential Misoperation beyond the 120 calendar day period. See proposed Requirement R4. Change made.</p>
<p>Bonneville Power Administration</p>	<p>No</p>	<p>(1) The changes made to R1 are an improvement over the previous draft, but they still do not adequately clarify the responsibilities. Both the Rationale for R1 (blue box) and the Application Guidelines indicate that the responsibility to investigate operations is placed on the owner of the interrupting device. However, BPA believes that the actual wording of R1 does not necessarily place the responsibility on the owner of the interrupting device. Instead, R1 places the responsibility on the TO, GO, or DP which has an interrupting device operation in its facility. Since it is quite common in the industry for TOs, GOs, or DPs to own interrupting devices within another entity’s facility, R1 will sometimes place the responsibility on the owner of the facility where the interrupting device is located instead of on the owner of the interrupting device.</p> <p>Response: Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners’ responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.</p> <p>In addition, the bullet points of R1 address the cases where the entity owns both the interrupting device and the protection system and where the entity owns the interrupting device but not all of the protection system, but there is no bullet point to address the case where the entity owns the protection system but not the interrupting device. It is not unusual for the owner of a facility to own a protection system but not the interrupting device that is operated by the protection system. Because it is vital that there is no ambiguity about who is responsible to initiate the investigation when an interrupting device operates, BPA recommends that the responsibility be placed on</p>

Organization	Yes or No	Question 2 Comment
		<p>the owner of the protective relays which caused the interrupting device to operate because the owner of the protective relays will have access to the primary information that will determine how the investigation should proceed. After the owner of the protective relays makes an initial investigation, the owners of the interrupting device or the owner of other components of the protection system can be notified to investigate their part of the protection system. If the responsibility to initiate the investigation is placed on the owner of the interrupting device, that entity will have to immediately turn to the owner of the protective relays to start the investigation.</p> <p>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. Requirement R1 was revised to bring clarity to the obligations of each applicable entity. Change made.</p> <p>(2) The use of Facility as defined by NERC in Requirement 1 does not make sense. As used in Requirement 1, Facility seems to indicate a substation or switching station, which is not in agreement with the NERC definition, which is a set of equipment that operates as a single element. BPA recommends that Facility not be used in Requirement R1 to avoid this problem.</p> <p>Response: Requirement R1 was revised to remove the use of "Facility." Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
ACES Standard Collaborators	No	<p>(1) Also it is still unclear who has the ultimate responsibility for identifying and reviewing each operation if the interrupting device and Protection System are owned by two or more parties. What should occur if there is disagreement over the responsibility or the ownership of a component? What if multiple parties owned</p>

Organization	Yes or No	Question 2 Comment
		<p>components that contributed to an operation or a Misoperation? Are both parties responsible? The rationale may provide additional guidance, but the words in the requirements are unclear.</p> <p>Response: Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. According to the standard, each entity has an independent responsibility to identify a Misoperation of its Protection System components, if any, beginning with the BES interrupting device owner through any notified Protection System owner. Change made.</p> <p>(2) "BES interrupting device" is not a defined term and is vague and ambiguous. We understand that devices that interrupt fault current, such as circuit breakers and circuit switchers would be included but what other devices such as motor operated disconnects? Are they not included because they don't interrupt any current? What if they are equipped to interrupt charging and load current? Failure to define "BES interrupting device" could result in an informal definition that results in inconsistent enforcement by including components outside of the scope of what is intended to be a BES interrupting device. This term adds uncertainty and creates opportunities for multiple interpretations.</p> <p>Response: The use of "BES interrupting device" has been clarified in the standard's Application Guidelines under the "Definitions" section. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
<p>Independent Electricity System Operator</p>	<p>No</p>	<p>1 We believe that R1 should be written more clearly, by saying that: "Within 120 calendar days of a BES interrupting device operation caused by a Protection System operation, each Transmission Owner, Generator Owner, or Distribution Provider - that owns the BES interrupting device - shall identify and review each Protection System Operation."</p>

Organization	Yes or No	Question 2 Comment
		<p>Response: Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.</p> <p>2 Also, there is a lack of clarity on which entity is responsible for developing and implementing a Corrective Action Plan. We believe that there has to be corresponding revisions to R2 and R3 to clearly indicate which entity needs to be held responsible for the CAP, especially in view of the rationale provided in the text box for R1, whose excerpt says:</p> <p>"The owner of the component that contributed to the Misoperation will create the CAP, action plan or declaration required by Requirements R2 and R3".</p> <p>We interpret the quoted excerpt (above) to mean that the component that contributed to the Misoperation may not be owned (in full or in part) by the owner of the BES interrupting device. It follows that in such cases, the owner of the component that contributed to the Misoperation is responsible for complying with R2 and R3. If this interpretation is correct, then Requirements R2 and R3 are not clear as to which entity is held responsible.</p> <p>To clarify this, we suggest revising the leading part of R2 to: "Each Transmission Owner, Generator Owner, or Distribution Provider that owns the component that contributed to the Misoperation shall, within 60 calendar days of identifying....". The Same revision should apply to R3, as follows: "Each Transmission Owner, Generator Owner, or Distribution Provider that owns the component that contributed to the Misoperation shall, within 180 calendar days of the associated BES interrupting device operation,....."</p> <p>Further, though not explicitly stated, we assume that the owner of the component that</p>

Organization	Yes or No	Question 2 Comment
		<p>contributed to the Misoperation is also held responsible for complying with R4 to implement and complete the CAP or action plan to accomplish all identified objectives. Hence, the same qualifier should also be added to Requirement R4.</p> <p>Response: The concept of an action plan has been eliminated from the standard; however, the proposed Requirement R4 requires the entity to perform investigative action when circumstances require additional study or time to determine the cause(s) of a Misoperation. Requirement R5 and R6 respectively address CAP development and implementation by the Protection System component owner to correct the cause(s) of a Misoperation. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
<p>Southern Company - Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Mississippi Power Company; Gulf Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing</p>	<p>No</p>	<p>1. The requirement R1 can be simplified by wording it in this manner: "Each entity shall identify, review, investigate, classify, document, and, for misoperations, determine the cause (if identified) of each Protection System operation that they own..." by the required time frame.</p> <p>Response: Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.</p> <p>2. The notification and response requirement of R1 is not needed, as the owner of the Protection System that operated is already required to investigate each operation in Requirement R1. An additional requirement for notifications and responses is superfluous.</p> <p>Response: Notification is necessary to require other owners of the Protection System</p>

Organization	Yes or No	Question 2 Comment
		<p>components to review their Protection System components for Misoperation. Notification and requirements for other owners have been removed from Requirement R1 and replaced by Requirements R2 and R3, respectively. Change made.</p> <p>3. There is a timing problem with R1.2 for the protection system owner who is notified on day 119 following a protection system operation. It is not reasonable or just to require this protection system owner to complete the requirements of R1 in one day's time after being notified by the owner of an interrupting device whose operation was suspected to be caused by a misoperation of another entity's protection system.</p> <p>Response: Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
American Electric Power	No	<p>AEP recommends the following modification to 1.1: "Within 120 calendar days of a BES interrupting device operation in its Facility caused by a BES Protection system operation or by manual intervention due to a BES Protection System failure to trip, identify and review each BES Protection System operation and BES Protection System failure to trip."</p> <p>Response: This suggestion has been incorporated into Requirement R1 to address manual intervention due to a BES Protection System failure to operate. Change made.</p> <p>AEP requests the standard be modified to clarify the liability of the notified entity if the notification occurs near the end of the 120 day period, and the notified entity does not have sufficient time to determine if their component operated properly or</p>

Organization	Yes or No	Question 2 Comment
		<p>misoperated within the 120 day period. AEP requests the standard be modified to clarify the liability of the notified entity if the notification occurs more than 180 days after the BES interrupting device operation.</p> <p>Response: Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.</p> <p>AEP requests that R1 should be modified to clearly indicate whether the term "entity" includes separate Functional Entities within the same Registered Entity. As written, it is unclear if the Transmission Owner function is required to notify the Generator Owner function within the same Registered Entity for compliance with R1.1 Bullet 2 or if the Registered Entity with multiple Functional Entities is treated as a single unit for ownership purposes.</p> <p>Response: The use of "entity" following the first use of the applicable entities (e.g., Distribution Provider, Generator Owner, and Transmission Owner) in the requirement is clear by the construction of the requirement. No change made.</p> <p>R1.2 appears to add little value as a standalone requirement. AEP recommends removing R1.2. and incorporating the requirement to identify a cause within the remaining R1 and R3 wording.</p> <p>Response: Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s)</p>

Organization	Yes or No	Question 2 Comment
		operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
American Transmission Company, LLC	No	<p>ATC believes that the investigation for relay misoperation should be performed by the owner of the initiating relay as opposed to the interrupting device owner for the following reasons:</p> <p>By definition, “Circuit breaker and other interrupting device mechanisms are not part of a Protection System”. As such, PRC-004 should not require the interrupting device owner to be responsible for R1.</p> <p>PRC-004 is based on Protection System operation, not breaker operation.</p> <p>Bus design can have multiple breakers owned by different entities but the ownership of the initiating relay is clear.</p> <p>The BES interrupting device owner lacks the information that the protective relay owner has to be able to perform a root cause analysis of a misoperation.</p>
<p>Response: The drafting team thanks you for your comment. 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. Requirement R1 was revised to bring clarity to the obligations of each applicable entity. Change made.</p>		
City of Austin dba Austin Energy	No	Austin Energy agrees with Luminant’s comment and copies it here for convenience. Requirement R1 requires all BES interrupting device operations be reviewed within 120 days. Under the Application Guidelines (Definition of a Misoperation - item 6 (page 17)), reverse power relaying used for normal unit shutdown is excluded. We recommend that this clarification be included in the Standard; either in language in the

Organization	Yes or No	Question 2 Comment
		Definition of a Misoperation (items 2, 5, and 6) or in Requirement R1.
<p>Response: The drafting team thanks you for your comment. According to the IEEE Guide for AC Generator Protection (C37.102-2006), Section 4.5.5 (Motoring), sub-section 4.5.5.6 (Tripping mode), “Primary motoring protection is provided by reverse power relays for all unit types.” Reverse power relays, by definition, are a Protection System and cannot be categorically excluded. Because reverse power relays provide motoring protection, the drafting team has provided an exclusion in the Applicability of the standard. Also, this exclusion is clarified in the Application Guidelines concerning the relay’s use as a control function for shutting down a unit and as anti-motoring protective protection for a generating unit. Change made.</p>		
CenterPoint Energy	No	CenterPoint Energy is concerned the wording of R1.1 to review a BES interrupting device “operation” within 120 days and the wording of R1.2 to investigate a “misoperation” within the same 120 day period of a BES interrupting device operation could be unworkable. The owner of the BES interrupting device could notify the owner of the Protection System component identified as contributing to the Misoperation well into the 120 day period, which would give the Protection System component owner little time to investigate and determine a cause. CenterPoint Energy recommends R1.2 wording be the following: “The owner of the Protection System component identified as contributing to the Misoperation shall investigate and document the findings for each Misoperation including a cause, if identified, by the latter of 120 days of a BES interrupting device operation or 30 days after receiving notification from the owner of the BES interrupting device.”
<p>Response: The drafting team thanks you for your comment. Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners’ responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.</p>		
Florida Municipal Power Agency	No	First, as currently drafted, R1 means that each investigation into a protection system operation is auditable, which in turn means that the definition of misoperation as

Organization	Yes or No	Question 2 Comment
		<p>discussed in question 1 need to be easily measurable. Please see discussion in question 1 about the difficulty in measuring: 1) “slower than intended”; 2) whether or not a Fault occurred; and 3) whether or not that Fault was “within the zone it was designed to protect”.</p> <p>Response: The phrase “slower than required” means the Composite Protection System operated slower than the objective of the owner(s). It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation was adequate. The intent is not to require documentation of exact Protection System operation times; however, each entity must determine what evidence it needs to support compliance with the requirements. The definition of Misoperation has been revised to clarify slow trips and additional detail added to the Application Guidelines. Change made.</p> <p>Second, there are numerous Protection System operations within a year, which results in a high-volume problem similar to those found in CIP standards, COM-003 and PRC-005. FMPA continues to recommend, as we did last time, that this standard would be better served by instituting internal controls language for R1 similar to what the CIP v5 and COM-003 SDTs adopted. Adopting such language would have the additional benefit of allowing the entity more latitude for how they deal with the ambiguities described in response to question 1.</p> <p>Response: The drafting team continues to support the proposed standard as currently structured. The draft requirements allow Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities. However, internal controls are only a mechanism to help auditors determine the depth and breadth of testing as it pertains to compliance with the related Reliability Standard and specific requirements and when necessary understand the facts and circumstances of instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process. No</p>

Organization	Yes or No	Question 2 Comment
		<p>change made.</p> <p>Third, FMPA commented last time that there ought to be an exception for Acts of Nature such as hurricanes and other natural disasters with, at minimum, the 120 day rule being waived. In response to FMPA’s comments, the SDT agreed with this concern. However, rather than change the standard, the response was: “The drafting team agrees with your comment about instances when major disturbances occur. As noted in the Guidelines and Technical Basis section of the standard, in the event of such natural disasters, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.” That means that the entity would still be in violation of the standard if it were not able to investigate all relay operations that occurred during a natural disaster. This is not acceptable to FMPA and we desire language to extend the time of the investigations as a result of Acts of Nature (e.g., a named storm, an earthquake that resulted in severe damage, etc. - maybe anytime a State’s Governor declares an emergency) to a longer hold the entity to the 120 day time period, e.g., but instead to a longer period such as 240 days, to allow time for more pressing disaster recovery efforts, without actually incurring multiple violations to the standard that would remain on the entities “record”.</p> <p>Response: <i>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.”</i> While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, including specific language in the proposed standard complicates a low frequency event where a compliance violation might occur. No change made.</p> <p>Fourth, there is no recognition that it is possible to have a condition where it cannot be determined whether the operation was correct or a Misoperation, e.g., if the location</p>

Organization	Yes or No	Question 2 Comment
		<p>of the fault cannot be determined, or whether a fault condition actually existed or not, especially for something like a trip with successful reclose. See the second point made in response to question 1 for further discussion.</p> <p>Response: Although it is true that it may be difficult to precisely locate a Fault, it is incorrect to consider that these events are indeterminate. As proposed in the PRC-004-3 standard, an entity is not required to precisely locate or find residual evidence of Faults nor is an entity required to install Disturbance Monitoring Equipment (DME). See Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018) for requirements concerning DME. In regards to the default assumption, an entity should review the documentation it can obtain for an event, and if there is no evidence of a Misoperation, then the entity should document the operation was correct. No change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
Hydro-Québec Procution	No	<p>In the previous version, the purpose has been centered on the reliability of the BES. The removal of that concept (reliability of the BES) implies the analysis of all the events that ocured on the BES have to be done, even if the event do not affect the reliability of the BES.</p>
<p>Response: The drafting team thanks you for your comment. The construction of Requirement R1 requires that each operation of a Protection System that causes a BES interrupting device operation must be reviewed to ensure that the Protection System responded correctly. An entity may choose to group operations by event; however, in the case of a single permanent fault caused an initial operation and a subsequent reclose and operation, all operations must be reviewed to determine if the Protection System responded appropriately. This achieves the objectives of the standard in ensuring correct performance of Protection Systems, as well as identifying and correcting the root causes of Misoperations which do affect reliability of the BES. No change made.</p>		
PacifiCorp	No	<p>In the second draft of PRC-004-3 PacifiCorp commented that the 120-day time limit in R1 is insufficient. PacifiCorp maintains that when two registered entities are involved in the interrupting device operation, 120 days is not enough time for both entities to complete the activities required by the requirement. PacifiCorp proposes an increase</p>

Organization	Yes or No	Question 2 Comment
		of 60 days for each entity to complete their respective activities in sequence. This would increase the total from 120 to 180 in R1.
<p>Response: The drafting team thanks you for your comment. Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners’ responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.</p>		
Ingleside Cogeneration LP	No	<p>Ingleside Cogeneration agrees that the owner of the tripping device should own the investigation and bring in other entities as needed. In addition, R1 takes out any guesswork about the responsibilities of each Protection System owner who may have contributed to the Misoperation.</p> <p>What we still do not understand is the recourse available to the Protection System owner if the request for assistance from an adjacent entity is sent late. The requirement does not account for the fact that a notification may be issued weeks after the fact - the 180 day assessment deadline applies regardless. Under these circumstances, the recipient may be forced to declare that a cause was not found, as allowed by R3, and develop an action plan to investigate further. However, this leaves that owner in the position to explain the delay to auditors; which we do not believe is appropriate. Even more concerning, there appears to be nothing that stops the CEA from deciding that the reduced interval was adequate and assessing a violation as a result.</p>
<p>Response: The drafting team thanks you for your comment. Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners’ responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection</p>		

Organization	Yes or No	Question 2 Comment
System component(s) caused a Misoperation. Change made.		
Wisconsin Electric Power Company	No	It is not appropriate to make the owner of the interrupting device responsible to investigate Protection System operations. Interrupting devices as such are not components of a Protection System as defined by NERC. Responsibility for this investigation should be solely with the owner of the Protection System initiating the operation, and/or the owner of the Protection System which failed to operate.
<p>Response: The drafting team thanks you for your comment. 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. Requirement R1 was revised to bring clarity to the obligations of each applicable entity. Change made.</p>		
Lincoln Electric System	No	LES recommends additional clarification be provided regarding the statement in R1.1 to “identify and review each Protection System operation”. As currently written, it is unclear how an entity would comply with R1.1 in the event that an incident involves multiple breaker operations with automatic reclosing, but were the result of a single cause. In such a scenario, would the entity be required to maintain separate documentation for investigation, designation, etc for each breaker operation?
<p>Response: The drafting team thanks you for your comment. The construction of Requirement R1 requires that each operation of a Protection System that causes a BES interrupting device operation must be reviewed to ensure that the Protection System responded correctly. An entity may choose to group operations by event; however, in the case of a single permanent fault caused an initial operation and a subsequent reclose and operation, all operations must be reviewed to determine if the Protection System responded appropriately. This achieves the objectives of the standard in ensuring correct performance of Protection Systems, as well as identifying and correcting the root causes of Misoperations which do affect reliability of the BES. No change made.</p>		
Colorado Springs Utilities	No	Please consider clarification of the terms “BES Protection System”, “Protection System”, “BES interrupting device” and “interrupting device” throughout the proposed

Organization	Yes or No	Question 2 Comment
		<p>standard. Specifically in R1.1 the proposed requirement states:</p> <p>Each Transmission Owner, Generator Owner, and Distribution Provider shall: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]</p> <p>1.1 Within 120 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation.</p> <p>The wording of this requirement infers that the proposed standard is intended to include investigation of non-BES protection systems that cause the operation of a BES interrupting device. While such investigation is sound business practice, it may be outside the intended scope of the standard. An example would be the operation of a load serving transformer (say a 230kv to 13.2 kv unit) differential Protection System that operates both a BES interrupting device (a 230kv circuit breaker) and a non-BES interrupting device (a 13.2kv circuit breaker). The stated purpose of this standard is to “Identify and correct the causes of Misoperations of Bulk Electric System (BES) Protection Systems” and is supported by the terminology used in the opening paragraph of the Background statement and the content of the Compliance section. Operation of a load serving facility protection system normally will have no impact on the reliability of the BES unless its failure to operate results in a subsequent operation of a BES bus differential Protection System or BES transmission element Protection System, for example. A similar argument can be offered for operation of protection system on non-BES radial lines and local network that cause operation of a high-side interrupting device which may also be part of a BES Protection System.</p> <p>Based on this line of thinking, it is proposed that the wording of requirement 1.1 be revised to state “Within 120 calendar days of an interrupting device operation in its Facility caused by a BES Protection System operation, identify and review each BES Protection System operation.” The wording of Requirements R1.2 and R3 should also be modified for consistency.</p>

Response: The drafting team thanks you for your comment. The occurrences of “BES Protection System” have been revised to

Organization	Yes or No	Question 2 Comment
<p>pertain to Protection Systems for BES Elements. The use of “BES interrupting device” has been clarified in the standard’s Application Guidelines under the “Definitions” section. Change made.</p>		
<p>Los Angeles Department of Water and Power</p>	<p>No</p>	<p>Please see answer to Question 5</p>
<p>Response: The drafting team thanks you for your comment; and refers to the response provided in Question 5.</p>		
<p>Madison Gas and Electric Company</p>	<p>No</p>	<p>Please see question 5.</p>
<p>Response: The drafting team thanks you for your comment; and refers to the response provided in Question 5.</p>		
<p>Public Service Enterprise Group</p>	<p>No</p>	<p>R1 addresses the situation where a BES interrupting device operation may be the result of the operation of a Protection System operation owned by an entity that does not own the BES interrupting device. As written, the owner of the BES interrupting device has no deadline to notify the owners of other Protection Systems when cannot determine that the Protection System operation was correct (the second bullet in Part 1.1).</p> <p>R1 presently allows 120 calendar days in total for the owner of the BES interrupting device to notify the other Protection System owners and for those other owners to determine if their Protection System operated correctly and if they did not, to document each Misoperation, including a cause if one can be identified. As drafted, the owner of the BES interrupting device could notify the other Protection System owners on the 119th day following the operation of its interrupting device, making it impossible for those other Protection System owners to perform their required analysis by the 120th day.</p> <p>The change identified to Part 1.1 below requires the owner of the BES interrupting device to make a notification to the other Protection System owners within 60 calendar days of the operation of its BES interrupting device if the situation described</p>

Organization	Yes or No	Question 2 Comment
		<p>above occurs. The changes to Part 1.2 below allows either Protection System owner 90 calendar days to document the findings of each Protection System Misoperation that may have occurred, making the total number of days allowed from the date of the operation of the BES interrupting device 150 calendar days. Only 30 calendar days has been added to the timeline, but this additional 30 days is needed to correct the potential inequity for owners of Protection Systems that do not own the BES interrupting device to complete their analysis.</p> <p>For consistency, 30 calendar days was added to the R3 timeline of 180 days, making it 210 days from the date of the operation of the associated BES interrupting. R2 is unchanged, but is shown for completeness.</p> <p>Response: Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.</p> <p>We have also added a provision in a footnote that allows a Regional Entity to extend deadlines that are referenced to the operation date of a BES interrupting device for instances such as natural disasters. Personnel that might normally evaluate the operation of a Protection System may not be available to do so due to their involvement in restoration efforts.</p> <p>Here is our suggested changes. Additional language is CAPITALIZED.</p> <p>R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]1.1 Within [delete "120"] 60 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, identify and review</p>

Organization	Yes or No	Question 2 Comment
		<p>each Protection System operation AND [FOOTNOTE 1];</p> <p>If the entity owns both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation, OR;</p> <p>If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System component(s) and provide any requested investigative information.</p> <p>The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component.</p> <p>FOOTNOTE 1: Such 60 day period and subsequent periods in the standard that have a deadline that references the operation date of a BES interrupting device may be extended by the Regional Entity for instances such as a natural disaster.</p> <p>1.2 Within the same [delete "120 day period"] 150 CALENDAR DAYS of a BES interrupting device operation caused by a Protection System operation, the owner of the Protection System component identified as contributing to the Misoperation shall investigate and document the findings for each Misoperation including a cause, if identified.</p> <p>R2. Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 60 calendar days of identifying the cause of each Misoperation: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning]</p> <p>Develop a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or</p> <p>Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability.</p> <p>R3. Each Transmission Owner, Generator Owner, or Distribution Provider shall, within</p>

Organization	Yes or No	Question 2 Comment
		<p>180 210 calendar days of the associated BES interrupting device operation, complete for each Misoperation without an identified cause: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning]</p> <p>Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or</p> <p>A declaration explaining why no further actions will be taken.</p> <p>Response: <i>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, including specific language in the proposed standard complicates a low frequency event where a compliance violation might occur. No change made.</i></p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
Northeast Utilities	No	<p>R1.1 second bulleted item states:</p> <p>If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System component(s) and provide any requested investigative information.</p> <p>The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component.</p> <p>This requirement statement is confusing and should be revised to clearly describe the intent. Additionally, this statement requires action by more than one entity within the 120 day time period. There is no requirement for BES interrupting device owner to</p>

Organization	Yes or No	Question 2 Comment
		<p>notify the owner of the protection system component identified as contributing to the misoperation prior to 120 days which could leave the protection system component owner no time to investigate and determine if the operation was correct or not as required in R1.1 and determine the cause as required in R1.2 (which also must be completed within the first 120 days). We suggest that the above statement be a separate requirement under R1 and be worded as follows:</p> <p>If the BES interrupting device owner cannot determine that the Protection System operation was correct, and concludes that protection system components owned by another entity contributed to a possible misoperation, the BES interrupting device owner shall notify the other owner(s) of the Protection System component(s) of their preliminary conclusions and provide any requested investigative information within 90 days of an interrupting device operation.</p> <p>It is suggested that a 90 day timeframe for this situation is still reasonable for the interrupting device owner and allows 30 days for the owner(s) of the Protection System component(s) to comply with the existing R1.1 and R1.2. During the 120 day review period, requirement 1.1 does not ensure that there will be adequate time for ALL Protection System owners to review the operation. If the BES interrupting device owner is tardy in informing another Protection System component owner, then that Protection System owner may not have time to perform a review. There should be some milestone within the 120 day review period where all Protection System owners need to be informed of the operation and their need to review it.</p>
<p>Response: The drafting team thanks you for your comment. Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners’ responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.</p>		
Pepco Holdings Inc & Affiliates	No	Requirement R1 places the responsibility on the BES interrupting device owner to

Organization	Yes or No	Question 2 Comment
		<p>investigate all operations initiated by a Protection System which trips the interrupting device. We vigorously disagree with this assignment of responsibility. The responsibility for R1 through R4 should be on the owner of the Protection System which initiated the tripping of the interrupting device, not the owner of the interrupting device. All previously approved versions of PRC-004 rightly place the responsibility for reviewing and analyzing Protective System operations on the owners of the Protective Systems, not the owners of the interrupting device. The interrupting device is, by definition, not even a component of a Protective System. Therefore, nowhere in this standard should compliance responsibility be assigned to the owner of an interrupting device.</p> <p>The entity who owns the interrupting device is not necessarily the one who owns the Protective System. For example, it is not uncommon for a generator to be interconnected to a TO switchyard, where the TO owns the breakers (interrupting devices) in the switchyard but the GO owns the Protection Systems protecting his generator unit. The GO Protection Systems trip the TO's breakers to isolate the unit from the system. The way the present standard is written the TO would be responsible for reviewing and identifying all GO protection initiated trips just because the TO owns the interrupting device. This is totally unreasonable. In a power plant, when a generator unit trips off line due to a plant Protective System operation lockout relays are employed to prevent re-energization of the unit until the cause of the trip can be determined. When this occurs, the investigation of this event should be initiated and pursued solely by the GO (i.e. the owner of the protective system that caused the tripping of the BES interrupting device) and not by the TO, who may happen to own the interrupting device. The GO may request data and information from the TO to assist in their investigation, however, all compliance responsibility for reviewing operations and identifying misoperations should solely rest on the owners of the Protective System(s) that initiated the trip of the BES facility (in this case the GO). In this case, involving the TO solely because they are the owner of the interrupting device places an unwarranted compliance burden on the TO. Although the TO may be aware that the interrupting device opened, they are not in a position to determine if it was</p>

Organization	Yes or No	Question 2 Comment
		<p>opened due to a plant Protective System operation, or was opened due to a manually initiated trip of the unit as it was being taken offline, since the GO, rather than the TO, usually has operational control over these breakers. In order to properly assign compliance responsibility to the appropriate entities, and eliminate the unwarranted compliance obligation on the interrupting device owner, we would suggest re-wording R1 in either one of two ways:</p> <p>OPTION 1 - Preferred: (assign responsibility to each Protection System owner rather than to the interrupting device owner)</p> <p>R1.1 “Within 120 calendar days of the operation of an interrupting device(s) which interrupts a BES Facility (i.e., line terminal, transformer, generator unit, etc.) that was caused by a Protective System operation, each Transmission Owner, Generator Owner, and Distribution Provider, who owns a Protective System which is connected to trip the interrupting device(s) shall review the event to determine if their Protection System operation was correct, or a misoperation.”</p> <p>With the above language the responsibility is clearly and properly assigned to the owner(s) of the Protective System(s) which initiated the tripping. We agree that if the owner of the relay that initiated the trip does not own all the remaining components of the associated Protection System (i.e., CTs or VT’s) they may require assistance and support from the owners of those additional components to complete their analysis. However, the owner of the Protective System that initiated the trip should be the party responsible for analyzing if a protective system misoperation occurred. If in the course of that investigation they determine the cause was attributed to a component of the Protection System which they did not own (such as a blown VT fuse owned by others), they should notify the other party, who would in turn be responsible for appropriate corrective action. While retaining this approach for shared Protection Systems the remaining Parts of Requirement R1 will also need to be re-worded to remove references to the interrupting device owner.</p> <p>OPTION 2 - Alternate: (replace owner of the interrupting device with owner of the interrupted BES Facility)</p>

Organization	Yes or No	Question 2 Comment
		<p>R1.1 “Within 120 calendar days of the interruption of a BES Facility (i.e., line terminal, transformer, generator unit, etc.) that was caused by a Protective System operation, the Transmission Owner, Generator Owner, and Distribution Provider, who owns the Facility that was interrupted shall identify and review each Protective System operation.</p> <p>If the entity owns both the BES Facility and the Protective System, determine if it was a correct operation, or a Misoperation.</p> <p>If the entity owns the BES Facility but does not own all of the Protective System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protective System component(s) and provide any requested investigative information. The Protective System component owner(s) that was notified by the Facility owner shall determine if there was a correct operation or a Misoperation of their component.</p> <p>1.2 Within the same 120 day period of the interruption of a BES Facility caused by a Protective System operation, the owner of the Protective System component identified as contributing to the Misoperation shall investigate and document the findings for each Misoperation including a cause, if identified.”</p> <p>The above language is consistent with the way TADS and GADS data is entered (i.e. by the Facility Owners). In addition, the Protective System(s) which protect and trip a specific Facility are almost entirely owned by the owners of the Facility. This Option adequately addresses the example raised previously, eliminating the need to involve the TO for generator initiated trips. The only complication arises when dealing with transmission lines terminating between two separate companies. The line terminals at each end may be owned by each respective company but the line itself may be entirely owned by only one company. To overcome this deficiency, this proposed re-write of R1 uses the term “line terminal” in the parenthetical list of BES Facilities. This would make the owners of the Protective Systems on each respective line terminal responsible for the review and analysis of their systems rather than the owner of the line itself.</p>

Organization	Yes or No	Question 2 Comment
<p>Response: The drafting team thanks you for your comment. 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. Requirement R1 was revised to bring clarity to the obligations of each applicable entity. Change made.</p>		
ReliabilityFirst	No	<p>Requirement R1 relies on the operation of an interrupting device and the identification by its owner that a Protection System operated and further that it may have operated due to a Misoperation. There are two issues with using this as the focal point of the actions within the standard.</p> <p>1) First, the owner of the interrupting device may not be in the best position to decide why the device operated, if a Protection System was involved and if a Protection System component contributed to a Misoperation. This partly is because the interrupting device excluding its trip coils and CTs is not part of the Protection System. The owner of the relay that activated the trip or the owner of the associated Disturbance Monitoring Equipment would be in a much better position to evaluate the operation. The requirement circumvents what may be a natural process of investigating the operation by its individual owners separately or collectively. The requirement may create a weak link in a chain because of its reliance on the interrupting device owner to start the identification and review process.</p> <p>2) Second, not all Misoperations result in an interrupting device operation particularly if no Fault occurred or the Fault is a high impedance transient Fault. The owner of the Protection System that failed to operate would not be required to investigate it.</p> <p>3) Finally, the requirement should be rewritten to obligate the owner of its Protection Systems to investigate their performance and to notify joint owners of their findings if they need to take follow up actions. Inserting the interrupting device owner unnecessarily into the process of investigation does not serve a reliability purpose but an administrative one.</p>

Organization	Yes or No	Question 2 Comment
<p>Response: The drafting team thanks you for your comment. 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. Requirement R1 was revised to bring clarity to the obligations of each applicable entity. Change made.</p>		
Texas Reliability Entity	No	See comments submitted in response to Question 5 below.
<p>Response: The drafting team thanks you for your comment; and refers to the response provided in Question 5.</p>		
Sacramento Municipal Utility District	No	See response under Question #5 with specific recommendations to implement Internal Controls.
<p>Response: The drafting team thanks you for your comment; and refers to the response provided in Question 5.</p>		
Public Utility District No. 1 of Snohomish County	No	See response under Question #5 with specific recommendations to implement Internal Controls.
<p>Response: The drafting team thanks you for your comment; and refers to the response provided in Question 5.</p>		
Liberty Electric Power LLC	No	The "same 120 days" could place an impossible burden on an entity notified late in the 120 day period. Notification that an issue with an entity's system contributed to a misoperation should start a new compliance clock.
<p>Response: The drafting team thanks you for your comment. Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.</p>		

Organization	Yes or No	Question 2 Comment
Tennessee Valley Authority	No	<p>The changed wording of R1 was an improvement. However, our concern comes from our company enduring a major natural disaster and the aftermath. When recovering from a major event 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 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 weeks and is not the top priority for a utility that endures such an event. The Standard needs wording to allow additional time when a utility endures a natural disaster.</p>
<p>Response: The drafting team thanks you for your comment. The <i>Sanction Guidelines of the North American Electric Reliability Corporation</i>, 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, including specific language in the proposed standard complicates a low frequency event where a compliance violation might occur. No change made.</p>		
Midwest Reliability Organization NERC Standards Review Forum (NSRF)	No	<p>The NSRF believes there should be exception for Acts of Nature such as tornados, ice storms and other natural disasters with, at minimum, the 120 day rule being waived. In previous comments the SDT agreed with this concern but did not add this exception. A wide spread thunderstorm with heavy lightning can set off multiple trips and recloses in a short time. There should be a process to exempt such events.</p> <p>Please verify that reclosing relays are not within scope of this Reliability Standard.</p>
<p>Response: The drafting team thanks you for your comment. The <i>Sanction Guidelines of the North American Electric Reliability Corporation</i>, 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, including specific language in the proposed standard complicates a low frequency event where a compliance violation might occur. No change made. Presently reclosing relays are not part of the definition of Protection System thus are excluded from the scope of this standard. No change made.</p>		

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	<p>The Protection System component owner who does not also own the interrupting device may be placed in a non-compliant situation through no fault of their own. Their compliance is contingent upon a timely notification from the owner of the BES interrupting device. If the notification is not made in a timely fashion to allow for investigation the Protection System component owner would be non-compliant for not conducting an investigation and documenting the findings within 120 days. For this situation the BES interrupting device owner should have an abbreviated time frame to notify the Protection System component owner to provide sufficient time to collect the appropriate information and investigate the operation. Conversely, the owner of the Protection System component could be granted more time to investigate (i.e. 120 days from the notification by the BES interrupting device owner).</p> <p>Response: Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.</p> <p>A misoperation investigation if Protection Systems are shared between two or more entities is often a joint effort. The Application Guide clearly defines that "it is expected that both entities will work together to investigate the cause of the operation", which is desired. This is not clearly defined in R1 and should be clarified. The Application Guide should indicate that this notification should be done as soon as possible.</p> <p>Response: Notification starts the period for the Protection System component owner to begin its investigation. If the BES interrupting device owner officially notifies other Protection System component owners when there may be no need to do so, it will create an unnecessary compliance obligation for the other owners, especially when there is little possibility that another owner's Protection System component(s) caused</p>

Organization	Yes or No	Question 2 Comment
		<p>a Misoperation. The requirements do not preclude the initial entity that is reviewing the operation from working with the other owners and when necessary, make the official notification. Requirement R1 has been revised to move notification into a separate new Requirement now R2. This requirement clarifies that the BES interrupting device must make notifications when (1) it share components of a Composite Protection System, (2) it determined a Misoperation or cannot rule out a Misoperation, and (3) its Protection System component(s) did not cause the BES interrupting device(s) operation or is unsure. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
<p>PPL NERC Registered Entities</p>	<p>No</p>	<p>The requirement R1 can be simplified by wording it in this manner: "Each entity shall identify, review, investigate, classify, document, and, for misoperations, determine the cause (if identified) of each Protection System operation that they own..." by the required time frame.</p> <p>There is a possible time coordination issue for identification and review of misoperations with R1.2. As stated in the proposed standard, R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection System. If timely communication of misoperation information is delayed by a Protection System component owner, the BES interrupting device owner could possibly bear the responsibility of not meeting the 120 day reporting requirement per R1. Fundamentally, R1 frames the time period for reviewing and analyzing a misoperations where multiple responsible entities are involved. However, R1 does not take in to account that one entity's analysis may be dependent upon the other's final analysis and that parallel review of misoperations are not possible. More consideration should be given to the cases where one entity's actions impact another's ability to meet the requirements of R1. However, concur in overall concept with clarifying coordination roles between BES interrupting device owner and the Protection System owner.</p>
<p>Response: The drafting team thanks you for your comment. Requirement R1 was split into two separate Requirements (R1 and R3) to</p>		

Organization	Yes or No	Question 2 Comment
		<p>provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.</p>
Essential Power, LLC	No	<p>The requirement R1 can be simplified by wording it in this manner: "Each entity shall identify, review, investigate, classify, document, and, for misoperations, determine the cause (if identified) of each Protection System operation that they own..." by the required time frame.</p> <p>There is a timing problem with R1.2 for the Protection System owner who is notified on day 119 following a Protection System operation. It is not reasonable or just to require this Protection System owner to complete the requirements of R1 in one day's time after being notified by the owner of an interrupting device whose operation was suspected to be caused by a Misoperation of another entity's Protection System.</p> <p>Response: Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.</p> <p>The evidence listing in M1 is unnecessarily duplicative. Measure M1 (and likewise all of R1) could be greatly simplified by stating that the required evidence for proving compliance with R1 may include, but is not limited to ...then list the items once.</p> <p>Response: The Measure has been revised for clarity and to be more concise. Change made.</p>

Organization	Yes or No	Question 2 Comment
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
<p>Cogentrix Energy Power Management, LLC</p>	<p>No</p>	<p>The requirement R1 can be simplified by wording it in this manner: "Each entity shall identify, review, investigate, classify, document, and, for misoperations, determine the cause (if identified) of each Protection System operation that they own..." by the required time frame. There is a timing problem with R1.2 for the Protection System owner who is notified on day 119 following a Protection System operation. It is not reasonable or just to require this Protection System owner to complete the requirements of R1 in one day's time after being notified by the owner of an interrupting device whose operation was suspected to be caused by a Misoperation of another entity's Protection System.</p> <p>Response: Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.</p> <p>The evidence listing in M1 is unnecessarily duplicative. Measure M1 (and likewise all of R1) could be greatly simplified by stating that the required evidence for proving compliance with R1 may include, but is not limited to ...then list the items once.</p> <p>Response: The Measure(s) have been revised for clarity and to be more concise. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
<p>City of Tallahassee</p>	<p>No</p>	<p>There should be some provision in the standard to take in to account extenuating circumstances such as natural disasters. It would be unfair to expect entities to be able</p>

Organization	Yes or No	Question 2 Comment
		<p>to perform an analysis within 120 days following a major disaster.</p> <p>Response: The <i>Sanction Guidelines of the North American Electric Reliability Corporation</i>, 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, including specific language in the proposed standard complicates a low frequency event where a compliance violation might occur. No change made.</p> <p>Also, there are some circumstances when an investigation is out of the control of the entity. For example if a relay or protection device potentially failed but needed to be investigated by the manufacturer or an outside company it may take longer than 120 days to perform a thoroughly investigation.</p> <p>Response: The standard now provides the entity an extended period for continuing its investigation of a potential Misoperation beyond the 120 calendar day period. See proposed Requirement R4. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
<p>City of Tallahassee - Electric Utility</p>	<p>No</p>	<p>There should be some provision in the standard to take into account extenuating circumstances such as natural disasters. It would be unfair to expect entities to be able to perform an analysis within 120 days following a major disaster.</p> <p>Response: The <i>Sanction Guidelines of the North American Electric Reliability Corporation</i>, 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, including specific language in the proposed standard complicates a low frequency event where a compliance violation</p>

Organization	Yes or No	Question 2 Comment
		<p>might occur. No change made.</p> <p>Also, there are some circumstances when an investigation is out of the control of the entity. For example, if a relay or protection device potentially failed but needed to be investigated by the manufacturer or an outside company, it may take longer than 120 days to perform a thorough investigation.</p> <p>Response: The standard now provides the entity a periodic time frame for continuing its investigation into the cause of a Misoperation. See the proposed Requirement R4. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
Consumers Energy	No	<p>There still seems to be a contradiction in R1 regarding the responsibilities of the BES interrupting device owner (IDO) vs. the Protection System owner (PSO) when owned by different entities (as we commonly have on the 138 system). The breaker, other than the trip coils and CTs, is not part of the Protection System, so the responsibility to investigate operations initiated by a protection system should be with the PSO. NERC’s response below to Q4 seems to agree with this (regarding documenting, CAP, and reporting), but R1 still places responsibility for investigation on the IDO. As a matter of fact, the Rationale for R1 added into draft 3 the statement “Requirement R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection System.”</p> <p>When an interrupting device operates, logically the IDO would investigate why their device operated. As soon as the IDO finds out that the operation was initiated by a protection system (the situation described in R1) they should then only have to notify the PSO of the situation (the PSO may not be aware of a protection system operation). The IDO would not be in the best position to investigate, and should not be validating Protection System operations for the PSO.</p> <p>The seems to be mostly a contradiction of the wording in R1 vs. the Rationale section. If the Rationale is not included in the final version of the standard, I could probably</p>

Organization	Yes or No	Question 2 Comment
		agree with the wording of the rest of it.
<p>Response: The drafting team thanks you for your comment. 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. Requirement R1 was revised to bring clarity to the obligations of each applicable entity. Change made.</p> <p>Notification starts the period for the Protection System component owner to begin its investigation. If the BES interrupting device owner officially notifies other Protection System component owners when there may be no need to do so, it will create an unnecessary compliance obligation for the other owners, especially when there is little possibility that another owner’s Protection System component(s) caused a Misoperation. The requirements do not preclude the initial entity that is reviewing the operation from working with the other owners and when necessary, make the official notification. Requirement R1 has been revised to move notification into a separate new Requirement now R2. This requirement clarifies that the BES interrupting device must make notifications when (1) it share components of a Composite Protection System, (2) it determined a Misoperation or cannot rule out a Misoperation, and (3) its Protection System component(s) did not cause the BES interrupting device(s) operation or is unsure. Change made.</p>		
ExxonMobil Research and Engineering	No	
SERC Protection and Controls Subcommittee	Yes	none
Entergy Services, Inc. (Transmission)	Yes	Since actual Misoperation data reporting will now be addressed outside of this standard, entity data communication requirements within this standard need to be consistent with respect to data reporting criteria. As an example, since there is no requirement for a contributing component entity owner to forward the required investigative and CAP data to the interrupting device entity owner, one would expect that reporting will be the responsibility of the Protection System contributing

Organization	Yes or No	Question 2 Comment
		component entity owner.
<p>Response: The drafting team thanks you for your comment. The NERC Rules of Procedure, Section 1600 Request for Information or Data (i.e., Data Request) will dictate the specific entity (i.e., Protection System component owner) that is to report a Misoperation and the format for reporting. Reporting under the standard will end. No change made.</p>		
ISO RTO Council Standards Review Committee	Yes	<p>There is a lack of clarity on which entity is responsible for developing and implementing a CAP.</p> <p>We agree with the revision to Requirement R1, but believe that there needs to be corresponding revisions to R2 and R3 to clearly indicate which entity needs to be held responsible, especially in view of the rationale provided in the text box for R1, whose excerpt says:</p> <p>“The owner of the component that contributed to the Misoperation will create the CAP, action plan or declaration required by Requirements R2 and R3”.</p> <p>We interpret the quoted excerpt (above) to mean that the component that contributed to the Misoperation may not be owned (in full or in part) by the owner of the BES interrupting device. It follows that in such cases, the owner of the component that contributed to the Misoperation is responsible for complying with R2 and R3. If this interpretation is correct, then Requirements R2 and R3 are not clear as to which entity is held responsible. To clarify this, we suggest to revise the leading part of R2 to:</p> <p>“Each Transmission Owner, Generator Owner, or Distribution Provider that owns the component that contributed to the Misoperation shall, within 60 calendar days of identifying....”.</p> <p>The Same revision should apply to R3, as follows:</p> <p>“Each Transmission Owner, Generator Owner, or Distribution Provider that owns the component that contributed to the Misoperation shall, within 180 calendar days of of the associated BES interrupting device operation,.....”</p> <p>Further, though not explicitly stated, we assume that the owner of the component that</p>

Organization	Yes or No	Question 2 Comment
		<p>contributed to the Misoperation is also held responsible for complying with R4 to implement and complete the CAP or action plan to accomplish all identified objectives. Hence, the same qualifier should also be added to Requirement R4.</p>
<p>Response: The drafting team thanks you for your comment. The concept of an action plan has been eliminated from the standard; however, the proposed Requirement R4 requires the entity to perform investigative action when circumstances require additional study or time to determine the cause(s) of a Misoperation. Requirement R5 and R6 respectively address CAP development and implementation by the Protection System component owner to correct the cause(s) of a Misoperation. Change made.</p>		
Georgia Transmission Corp	Yes	<p>While reporting falls under 1600, should PRC-004 clarify which of the two should file the Misoperation?</p>
<p>Response: The drafting team thanks you for your comment. The NERC Rules of Procedure, Section 1600 Request for Information or Data (i.e., Data Request) will dictate the specific entity (i.e., Protection System component owner) that is to report a Misoperation and the format for reporting. Reporting under the standard will end. No change made.</p>		
Mary Jo Cooper	Yes	
seattle city light	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
City of Tacoma, Tacoma Public Utilities	Yes	
Dominion	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 2 Comment
Arizona Public Service Company	Yes	
Operational Compliance	Yes	
Western Electricity Coordinating Council	Yes	
Rayburn Country Electric Cooperative	Yes	
Xcel Energy	Yes	
ITC Holdings	Yes	
Manitoba Hydro	Yes	
Tri-State G&T	Yes	
Exelon Corporation and it's affiliates	Yes	
Idaho Power Company	Yes	
Ameren	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Nebraska Public Power District	Yes	

Organization	Yes or No	Question 2 Comment
Oncor Electric Delivery Company LLC	Yes	
Public Service Company of New Mexico	Yes	

- 3. The Measures and VSLs were revised to reflect changes to the requirements. Do you agree with these changes? If not, please provide specific reasons why not and alternative recommendations and justifications.**

Summary Consideration:

The following resulted in a revision to the proposed standard. Due to the significant changes to the proposed standard (e.g., removal of the action plan), the Violation Severity Levels (VSL) have been rewritten to align with the revised Requirements. The drafting team contends that the revisions to the Requirements have resulted in more understandable VSLs. Likewise, there were at least seven comments supported by about 57 individuals that suggested revisions to the Measures. The drafting team also revised the Measures to focus on evidence examples and to be more concise.

Approximately seven comments represented by 23 stakeholders expressed concern with the escalation values in the VSLs. Because the new version of the VSL Guidelines provides more flexibility in the intervals, the drafting team has responded by increasing the interval periods for Requirement R1.

Although summarized earlier, about three comments represented by at least 13 individuals were concerned about ambiguity with the time periods for completing its investigation. The proposed standard now provides the entity a periodic time frame for continuing its investigation into the cause of the Misoperation beyond the 120 calendar day period in Requirement R1, Part 1.4.

Also summarized earlier, at least two comments supported by about eight stakeholders expressing concern about the time period for an entity that is notified to review its Protection System for Misoperation. Requirement R1 was revised to provide clarity on each Protection System owners' responsibilities following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components, time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.

Several comments suggested minor editorial clarifications which were implemented by the drafting team.

The following did not result in a change to the proposed standard. The following did not result in a change to the proposed standard. Approximately two comments supported by eight individuals wanted to use percentages for determining the level of violations. The drafting team contends that a weighting factor (i.e., use of percentages) is the most practical for assessing violations for fixed quantities and not for the VSLs in this proposed standard.

Organization	Yes or No	Question 3 Comment
Ameren	No	(1) We disagree with the VSL escalation, for R1, R2 and R3, from Moderate to High to Severe at 10 days interval each.
<p>Response: The drafting team thanks you for your comment. In the previous posting, the drafting team followed the guidelines for VSL escalation that were in effect at the time. However, the current version of the Violation Severity Level Guidelines provides more flexibility in the interval. Based on comments received, the drafting team increased the interval for Requirement R1 (including the new R2 and R3) severity levels to 30 days for the Lower VSL and 15 calendar days for the Moderate and High VSL. The interval for creation and implementation of the CAP in Requirements R5 and R6 (previously R2 & R4) have been updated. Change made.</p>		
ACES Standard Collaborators	No	(1) The measures are not consistent with the revisions to the requirements. For instance, Requirement R1 requires the owner of the component that led to the Misoperation to identify and review its performance. However, the Measures require the applicable entities to have evidence without any statement regarding the ownership of Protection Systems or circuit breakers.
<p>Response: The drafting team thanks you for your comment. The Measure(s) have been revised for clarity and to be more concise. Change made.</p>		
Southern Company - Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Mississippi Power Company; Gulf Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	<p>1. The evidence listing in M1 is unnecessarily duplicative. Measure M1 (and likewise all of R1) could be greatly simplified by stating that the required evidence for proving compliance with R1 may include, but is not limited to ...then list the items once.</p> <p>Response: The Measure(s) have been revised for clarity and to be more concise. Change made.</p> <p>2. The severe VSL for R1, R2, and R3 can be simplified by changing a few words in the first item of each requirement.</p> <p>For R1, change "...entity performed the actions in ... and 1.2 in more than 170..." to "...entity did not perform the actions in and 1.2 within 170 ...". This would allow the 2nd and 3rd items in the OR statement to be eliminated.</p> <p>For R2, change "entity developed a CAP, or a declaration R2, more than 90 ..." to</p>

Organization	Yes or No	Question 3 Comment
		<p>"entity did not develop a CAP or a declaration ...R2 within 90 ...". This would allow the second part of the OR statement to be eliminated.</p> <p>For R3, change "entity developed an action plan, or made a declaration ... R3, more than 230 ..." to "entity did not develop an action plan or make a declaration ... R3 within 230 ...". This would allow the second part of the OR statement to be eliminated.</p> <p>Response: The VSL have been extensively revised due to the revisions to the requirements. Change made.</p> <p>3. The VSL should be have a weighting factor in the % of operations not analyzed (otherwise it is one strike and you're out and this could be one event out of many). Equal severity for 1/10 events is not just compared to 1/100 events.</p> <p>Response: A weighting factor (i.e., use of percentages) is practical for assessing violations for fixed quantities, because Protection System operations are variable and event driven. The drafting team constructed the VSL according to the NERC Violation Severity Level Guidelines. No change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
American Electric Power	No	<p>AEP recommends adjusting the time requirements specified in the VSL tables for R1, R2 and R3 to extend the timeframe for Moderate and High VSLs to 20 days, and eliminate the time requirement for the Severe VSL. Example: For R1, the Low VSL remains the same, Moderate becomes >150 to 170, High becomes >170 to 190, and Severe only applies when "The responsible entity failed to identify and review...".</p> <p>Response: In the previous posting, the drafting team followed the guidelines for VSL escalation that were in effect at the time. However, the current version of the Violation Severity Level Guidelines provides more flexibility in the interval. Based on comments received, the drafting team increased the interval for Requirement R1 (including the new R2 and R3) severity levels to 30 days for the Lower VSL and 15 calendar days for the Moderate and High VSL. The interval for creation and</p>

Organization	Yes or No	Question 3 Comment
		<p>implementation of the CAP in Requirements R5 and R6 (previously R2 & R4) have been updated. Change made.</p> <p>Measure M1 repeatedly lists the same evidence examples and AEP suggests simplifying the measure by stating “evidence for R1 may include but is not limited to....” followed by a single list of items.</p> <p>Response: The Measure(s) have been revised for clarity and to be more concise. Change made.</p> <p>The wording for the R4 VSL references failure to revise a CAP “as needed”. This statement is very broad, may be subject to interpretation and should be clarified or removed from the VSL.</p> <p>Response: The VSL was modified to be consistent with the revised CAP implementation requirement and to clarify the violation is on the CAP that was not updated when actions or timetables changed. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
Arizona Public Service Company	No	<p>Agree with the other changes but VSL severity levels are spaced 10 days apart. It should be at least 30 days apart. It is not justifiable to go from Lower to Sever VSL for 22 days of delay (149 days to 171 days). There is no justification for such strict time lines.</p>
<p>Response: The drafting team thanks you for your comment. In the previous posting, the drafting team followed the guidelines for VSL escalation that were in effect at the time. However, the current version of the Violation Severity Level Guidelines provides more flexibility in the interval. Based on comments received, the drafting team increased the interval for Requirement R1 (including the new R2 and R3) severity levels to 30 days for the Lower VSL and 15 calendar days for the Moderate and High VSL. The interval for creation and implementation of the CAP in Requirements R5 and R6 (previously R2 & R4) have been updated. Change made.</p>		
Tennessee Valley Authority	No	<p>As per Req. 2 - CAP Development is too stringent. Troubleshooting and determining which element could take longer than the time allowed in the VSLs. Under PRC-004-1</p>

Organization	Yes or No	Question 3 Comment
		<p>a 12 month time period was given to develop and implement a CAP.</p> <p>Response: The standard now provides the entity an extended period for continuing its investigation of a potential Misoperation beyond the 120 calendar day period. See proposed Requirement R4. Change made.</p> <p>Recommend a CAP not developed w/in 120 days or a declaration in accordance with Req. R3 (Lower VSL), CAP not developed w/in 120 days or a declaration in accordance with Req. R3 w/in 120 days or CAP declared in accordance with Req. R2 not implemented within 150 days (Medium VSL), CAP not developed w/in 150 days or a declaration in accordance with Req. R3 w/in 150 days or CAP declared in accordance with Req. R2 not implemented w/in 180 days (High VSL), CAP not developed w/in 180 days or a declaration in accordance with Req. R3 w/in 180 days or CAP declared in accordance with Req. R2 not implemented w/in 210 days.</p> <p>Response: In the previous posting, the drafting team followed the guidelines for VSL escalation that were in effect at the time. However, the current version of the Violation Severity Level Guidelines provides more flexibility in the interval. Based on comments received, the drafting team increased the interval for Requirement R1 (including the new R2 and R3) severity levels to 30 days for the Lower VSL and 15 calendar days for the Moderate and High VSL. The interval for creation and implementation of the CAP in Requirements R5 and R6 (previously R2 & R4) have been updated. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
ISO RTO Council Standards Review Committee	No	As we noted in our comments in the previous draft, the VSLs should recognize that some relay misoperations place a greater risk/impact on the BES than others.
<p>Response: The drafting team thanks you for your comments. A Violation Severity Level (VSL) is a measure of how badly did the entity violated the requirement which, in this case, applies to all Protection Systems for BES Elements. Providing a risk-based VSL would reward an entity (i.e., safe harbor) for failing to identify a Misoperation and correcting the cause for a Protection System that may have a lower risk to the BES. The objective of the standard is to identify and correct the causes of Misoperations of Protection</p>		

Organization	Yes or No	Question 3 Comment
<p>Systems for BES Elements. The Compliance Enforcement Authority will assess the circumstances concerning potential violations. No change made.</p> <p>As stated in response to your previous comments, the FERC-approved description of “Violation Risk Factor” is “Each requirement must have an associated violation risk factor (High, Medium, or Lower). The risk factor is one of several elements used to determine an appropriate sanction when the associated requirement is violated. The risk factor assesses the impact to reliability of violating a specific requirement.”</p> <p>However, the NERC Sanction Guidelines state that “Violation Risk Factors are assigned to standards’ requirements as indicators of the expected risk or harm to the bulk power system posed by the violation of a requirement by a typical or median entity that is required to comply. NERC or the regional entity may consider the specific circumstances of the violator to determine if the violation of the requirement in question actually produced the degree of risk or harm anticipated by the Violation Risk Factor. If that expected risk or harm was not or would not have been produced, NERC or the regional entity may set the Base Penalty Amount to a value it (i) deems appropriate and (ii) is within the initial value range set above pursuant to Section 4.1.” The drafting team believes that the NERC Sanction Guidelines address your comment.</p>		
Hydro-Québec Procution	No	<p>In the previous version, the purpose has been centered on the reliability of the BES. The removal of that concept (reliability of the BES) implies the analysis of all the events that occurred on the BES have to be done, even if the event do not affect the reliability of the BES.</p>
<p>Response: The drafting team thanks you for your comment. The construction of Requirement R1 requires that each operation of a Protection System that causes a BES interrupting device operation must be reviewed to ensure that the Protection System responded correctly. An entity may choose to group operations by event; however, in the case of a single permanent fault caused an initial operation and a subsequent reclose and operation, all operations must be reviewed to determine if the Protection System responded appropriately. This achieves the objectives of the standard in ensuring correct performance of Protection Systems, as well as identifying and correcting the root causes of Misoperations which do affect reliability of the BES. No change made.</p>		
Manitoba Hydro	No	<p>M1 - DME is not defined.</p> <p>Response: The abbreviation “DME” is a NERC defined term and acronym in the NERC Glossary of Terms Used in NERC Reliability Standards. For clarity, the acronym has</p>

Organization	Yes or No	Question 3 Comment
		<p>been spelled out. Change made.</p> <p>M3 - What was the reason for removing the words at the end 'explaining why no further investigation or actions will be taken' - these words are helpful and should be retained.</p> <p>Response: The phrase was redundant with the Requirement. No change made.</p> <p>VSLs - R1 - Severe VSL - the final option in this column seems to suggest that you would need both a failure to notify the other owners AND a failure to provide any investigative information. It doesn't contemplate a situation where an entity may have notified the other owners but failed to provide investigative information.</p> <p>Response: The requirement to provide investigative information was removed from the standard. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
Pepco Holdings Inc & Affiliates	No	<p>Measure M1 requires evidence “that documents the date and time of each applicable interrupting device operation and indicates when each related Protective System Operation was reviewed.” Based on our comments from Question 2 and proposed re-wording of Requirement R1, Measure M1 should also be revised to require evidence “that documents the date and time that each BES Facility was interrupted due to the operation of a Protection System and the date the Protection System operation was reviewed.”</p>
<p>Response: The drafting team thanks you for your comment. The Measure(s) have been revised for clarity and to be more concise. Change made.</p>		
PacifiCorp	No	<p>PacifiCorp is concerned that the VSLs are not commensurate with the reliability risk of the associated violations. In many cases, the difference between a “Lower” and a “Severe” VSL is an arbitrary additional number of days during which the reporting or documentation requirement was not satisfied. The fact that a report is an additional</p>

Organization	Yes or No	Question 3 Comment
		<p>30 days late should not increase the VSL from “Lower” to “Severe.” A later report does not increase the likelihood of additional adverse impact to the BES. A registered entity’s failure to remediate a protection issue is much more critical. A more reasonable timeframe for the VSLs would be 20 days per severity level instead of the proposed 10 days.</p> <p>PacifiCorp recognizes that the drafting team has made this change for the “Lower” VSL in Draft 3, but the remaining VSLs still reflect the 10 day timeframe.</p> <p>Response: In the previous posting, the drafting team followed the guidelines for VSL escalation that were in effect at the time. However, the current version of the Violation Severity Level Guidelines provides more flexibility in the interval. Based on comments received, the drafting team increased the interval for Requirement R1 (including the new R2 and R3) severity levels to 30 days for the Lower VSL and 15 calendar days for the Moderate and High VSL. The interval for creation and implementation of the CAP in Requirements R5 and R6 (previously R2 & R4) have been updated. Change made.</p> <p>Moreover, in keeping with PacifiCorp’s comment under Question 1, the “Lower” VSL should be amended from 120 calendar days to 180 calendar days to allow each entity enough time to complete their respective activities before incurring a violation of the standard.</p> <p>Response: Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners’ responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.</p> <p>Response: The standard now provides the entity an extended period for continuing its</p>

Organization	Yes or No	Question 3 Comment
		investigation of a potential Misoperation beyond the 120 calendar day period. See proposed Requirement R4. Change made.
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
Los Angeles Department of Water and Power	No	Please see answer to Question 5
<p>Response: The drafting team thanks you for your comment; and refers to the response provided in Question 5.</p>		
Kansas City Power & Light	No	R4 VSL wording is not clear as presently stated; "The responsible entity failed to revise a CAP or action plan as needed in accordance with Requirement R4." It might not be intended, however this wording implies that all CAP's must be revised and if not revised there is a compliance issue. The wording should state; "A CAP revision was needed in accordance with R4 and the responsible entity failed to make the revision."
<p>Response: The drafting team thanks you for your comment. The VSL was modified to be consistent with the revised CAP implementation requirement and to clarify the violation is on the CAP that was not updated when actions or timetables changed. Change made.</p>		
Flathead Electric Cooperative, Inc.	No	ramping up the violation level simply on the number of days that pass to complete the analysis does not seem appropriate for situations where the discovery may have been delayed in the first place
<p>Response: The drafting team thanks you for your comment. In the previous posting, the drafting team followed the guidelines for VSL escalation that were in effect at the time. However, the current version of the Violation Severity Level Guidelines provides more flexibility in the interval. Based on comments received, the drafting team increased the interval for Requirement R1 (including the new R2 and R3) severity levels to 30 days for the Lower VSL and 15 calendar days for the Moderate and High VSL. The interval for creation and implementation of the CAP in Requirements R5 and R6 (previously R2 & R4) have been updated. The standard now provides the entity an extended period for continuing its investigation of a potential Misoperation beyond the 120 calendar day period. See proposed Requirement R4. Change made.</p>		

Organization	Yes or No	Question 3 Comment
Essential Power, LLC	No	See comments to question 2
Response: The drafting team thanks you for your comment; and refers to the response provided in Question 2.		
Cogentrix Energy Power Management, LLC	No	See comments to question 2
Response: The drafting team thanks you for your comment; and refers to the response provided in Question 2.		
Sacramento Municipal Utility District	No	The current Requirements and their current approach are not supported as noted in the response in Question #5. As such the VSL and Measures cannot be supported.
Response: The drafting team thanks you for your comment; and refers to the response provided in Question 5.		
Public Utility District No. 1 of Snohomish County	No	The current Requirements and their current approach are not supported as noted in the response in Question #5. As such the VSL and Measures cannot be supported.
Response: The drafting team thanks you for your comment; and refers to the response provided in Question 5.		
PPL NERC Registered Entities	No	<p>The VSLs are hard-wired to response/reporting timelines specified per R1-R3. Some consideration should be given to technical complexity and circumstance of the SPS Misoperation.</p> <p>Response: The VSLs assess time-based violations based on factors such as, the BES interrupting device operation, notification, and creation of the Corrective Action Plan (CAP). Requirements for SPS Misoperation analysis and corrective action are addressed in PRC-016, not this standard. No change made.</p> <p>The R1 evidence listing in M1 is unnecessarily duplicative. Measure M1 (and likewise all of R1) could be greatly simplified by stating that the required evidence for proving compliance with R1 may include, but is not limited to ...then list the items once.</p> <p>Response: The Requirement(s) and Measure(s) have been revised for clarity and to be</p>

Organization	Yes or No	Question 3 Comment
		more concise. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Mary Jo Cooper	No	<p>This Standard allows 120 days for the entity to investigate the operation. We do not feel that this activity warrants a severe violation factor if only 1 operation was investigated 50 days later. We agree that if an activity has a significant impact on the BES than the violation severity level should be higher. In this case, however, immediate action is not required and therefore we disagree with the severe violation penalty suggested by the drafting team.</p> <p>Response: In the previous posting, the drafting team followed the guidelines for VSL escalation that were in effect at the time. However, the current version of the Violation Severity Level Guidelines provides more flexibility in the interval. Based on comments received, the drafting team increased the interval for Requirement R1 (including the new R2 and R3) severity levels to 30 days for the Lower VSL and 15 calendar days for the Moderate and High VSL. The interval for creation and implementation of the CAP in Requirements R5 and R6 (previously R2 & R4) have been updated. Change made.</p> <p>We suggest that the penalty for not investigating an operation timely should only qualify for a moderate VSL given immediate (within 1 hour or 1 day) activity is not required. We feel investigation of all operations and determination and implementation of correction misoperations is important to the long-term reliability of the BES. However, the system should be designed with redundancies to resolve any short-term issues and this Standard, while important, is designed to ensure long-term protection. Furthermore, we are not aware of any company who feels that the violation severity level determines whether they comply or not. Our organization strives to comply with all Standards with no violations, regardless of the violation severity level.</p> <p>Response: Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners’</p>

Organization	Yes or No	Question 3 Comment
		responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
Northeast Power Coordinating Council	No	We agree with the content of all the measures and VSLs, however measure M1 would have to be modified accordingly to coincide with the modifications suggested in question 2 above.
<p>Response: The drafting team thanks you for your comment. The Measure(s) have been revised for clarity and to be more concise. Change made.</p>		
Northeast Utilities	No	We agree with the content of all the measures and VSLs, however measure M1 would have to be modified accordingly to coincide with the modifications suggested in question 2 above.
<p>Response: The drafting team thanks you for your comment. The Measure(s) have been revised for clarity and to be more concise. Change made.</p>		
ExxonMobil Research and Engineering	No	
SERC Protection and Controls Subcommittee	Yes	none
Tri-State G&T	Yes	The first instance of the abbreviation, DME, is undefined in M1 on page 7. It is defined as Disturbance Monitoring Equipment on page 19 in the Guidelines and Technical

Organization	Yes or No	Question 3 Comment
		Basis section for R1. The definition should be moved to page 7.
<p>Response: The drafting team thanks you for your comment. The abbreviation “DME” is a NERC defined term and acronym in the NERC Glossary of Terms Used in NERC Reliability Standards. For clarity, the acronym has been spelled out. Change made.</p>		
Exelon Corporation and it’s affiliates	Yes	<p>The following changes are suggested:</p> <p>R1 - Add a Lower VSL condition that states, “The responsible entitiy failed to identify and review at least 2% or 2 (whichever is greater) Protection System operations that operated one of its BES interrupting devices in accordance with Requirement R1, Part 1.1”.</p> <p>Add a Moderate VSL condition that states, “The responsible entitiy failed to identify and review at leastr 3% or 3 (whichever is greater) Protection System operations that operated one of its BES interrupting devices in accordance with Requirement R1, Part 1.1”.</p> <p>Add a High VSL condition that states, “The responsible entitiy failed to identify and review at least 4% or 4 (whichever is greater) Protection System operations that operated one of its BES interrupting devices in accordance with Requirement R1, Part 1.1”.</p> <p>Modify the 2nd Severe VSL condition with, “The responsible entitiy failed to identify and review at least 5% or 5 (whichever is greater) Protection System operations that operated one of its BES interrupting devices in accordance with Requirement R1, Part 1.1”.</p> <p>Response: A weighting factor (i.e., use of percentages) is practical for assessing violations for fixed quantities, because Protection System operations are variable and event driven. The drafting team constructed the VSL according to the NERC Violation Severity Level Guidelines. No change made.</p> <p>Eliminate the 2nd Lower VSL condition all together because it is redundant with the 1st Severe VSL condition that addresses performing the actions in accordance with</p>

Organization	Yes or No	Question 3 Comment
		<p>Requirement R1, Parts 1.1 and 1.2 in more than 170 days.</p> <p>Response: The standard has been revised to provide one activity for a single reliability goal in accordance with standard drafting guidelines. The drafting team restructured the previous requirements into separate requirements which required the VSLs to be modified substantively. Change made.</p> <p>R2 - Eliminate the last Severe VSL condition that is listed because it is redundant with the 1st Severe VSL condition listed.</p> <p>R3 - Eliminate the last Severe VSL condition that is listed because it is redundant with the 1st Severe VSL condition listed.</p> <p>R4 - Eliminate the last Severe VSL condition that is listed because it is redundant with the 1st Severe VSL condition listed.</p> <p>Response: The VSL parts are not redundant. One part addresses a completed action, but was late and the other an incomplete action. No change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
Colorado Springs Utilities	Yes	
seattle city light	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
City of Tacoma, Tacoma Public Utilities	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 3 Comment
Bonneville Power Administration	Yes	
Operational Compliance	Yes	
Rayburn Country Electric Cooperative	Yes	
Georgia Transmission Corp	Yes	
Xcel Energy	Yes	
ITC Holdings	Yes	
Lincoln Electric System	Yes	
ReliabilityFirst	Yes	
Idaho Power Company	Yes	
Texas Reliability Entity	Yes	
Entergy Services, Inc. (Transmission)	Yes	
Ingleside Cogeneration LP	Yes	
Nebraska Public Power District	Yes	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 3 Comment
Oncor Electric Delivery Company LLC	Yes	
Public Service Company of New Mexico	Yes	
City of Austin dba Austin Energy	Yes	

4. The drafting team modified the Guidelines and Technical Basis section to provide more supporting discussions, explanations, and examples for the various aspects of the standard. Do you have any specific suggestions for further improvements?

Summary Consideration:

The following resulted in a revision to the proposed standard. The most significant comment here was presented by at least four comments supported by 20 individuals concerning the use of “composite Protection System.” The composite Protection System is the collective operation of the entire Protection System for an Element which is included in determining whether a Misoperation occurred. To clarify the usage of the terminology, the drafting team is proposing the term “Composite Protection System” which has an exclusion for backup protection provided by a remote Protection System.

Approximately four comments from individuals were concerned about the use of reverse power relays. Because reverse power relays provide anti-motoring protection for generators, the drafting team has clarified in the Application Guidelines the relay’s protective function intended use as a control function for shutting down a generating unit and as anti-motoring protection.

The remaining narrative responds to comments from two or fewer comments that are not addressed in other summaries:

- The Application Guidelines have been clarified not to infer the implementation of the CAP must be completed in 180 days (See draft 3, page 20 “...and requires the CAP implementation be less than 180 days.”). The CAP has its own timetable which is required to be updated by the entity when actions or timetables change.
- Requirement R4 now addresses the “action plan” as investigative action the entity performs when circumstances require additional study or time to determine the cause of a Misoperation. Requirement R5 and R6 respectively address CAP development and implementation by the Protection System component owner to correct the cause(s) of a Misoperation.

Other single comments were too numerous and different to summarize here. Please see the comments below for these comments.

Organization	Yes or No	Question 4 Comment
ACES Standard Collaborators	No	(1) If the drafting team intends to move forward with “composite Protection System,” we recommend adding it as a new proposed definition. After reading the technical guidelines, we are not persuaded that the drafting team has articulated the difference

Organization	Yes or No	Question 4 Comment
		<p>between a Protection System and a composite Protection System. A proposed glossary term would allow industry the opportunity to provide the feedback as to whether an additional term is needed in order to have the proper scope for identifying Misoperations.</p>
<p>Response: The drafting team thanks you for your comment. The use of the term “composite” Protection System is intended to address the fact that the term Protection System by itself does not indicate that it is the complete set of protective relaying for an Element such as any primary, secondary, local backup, and communication-assisted relay systems. The word “composite” used as a modifier to Protection System was developed by the NERC SPCS to indicate the total complement of protection for a system Element (line, bus, transformer, generator, etc). To clarify the usage of the terminology, the drafting team is proposing a definition for “Composite Protection System” and has made corresponding changes where “composite Protection System” occurs in the body of the project documents. Change made.</p>		
American Electric Power	No	<p>AEP recommends adding "remote backup relaying is not considered to be part of the composite Protection System" to the end of the description for the composite Protection System in the Application Guidelines.</p> <p>Response: This recommendation has been incorporated into the proposed term “Composite Protection System.” Change made.</p> <p>AEP requests that SDT include a clarification of the meaning of "BES interrupting device" within the context of this standard (similar to how "composite Protection System" is addressed).</p> <p>Response: The use of “BES interrupting device” has been clarified in the standard’s Application Guidelines under the “Definitions” section. Change made.</p> <p>AEP recommends replacing both instances of the word "implementation" with "development" in the second paragraph of page 20 of the clean version of the standard. Otherwise it is implied that there are situations where a CAP must be fully implemented within 180 days.</p> <p>Response: The Application Guidelines have been clarified not to infer the implementation of the CAP must be completed in 180 days (See draft 3, page 20 “...and</p>

Organization	Yes or No	Question 4 Comment
		<p>requires the CAP implementation be less than 180 days.”). The CAP has its own timetable which is required to be updated by the entity when actions or timetables change. Change made.</p> <p>Please include a clarification of the CAP and action plan modification tracking. For example, if a CAP or action plan is modified, is it sufficient to document the modifications, or must the date the modifications were made also be tracked?</p> <p>Response: The concept of an action plan has been eliminated from the standard; however, the proposed Requirement R4 requires the entity to perform investigative action when circumstances require additional study or time to determine the cause(s) of a Misoperation. Requirement R5 and R6 respectively address CAP development and implementation by the Protection System component owner to correct the cause(s) of a Misoperation. Change made.</p> <p>The Measure M6 includes “dated” documentation to improve clarity. Also, examples were added to the Application Guidelines under Requirement R6. Change made.</p> <p>On page 15 of the clean version of the standard AEP recommends adding “unintentional” before “loss of field” in the first paragraph.</p> <p>Response: See Example 2a in the Application Guidelines under the Misoperation category 2 (Failure to Trip – Other Than Fault) discussion. Change made.</p> <p>On page 15 of the clean version of the standard AEP recommends replacing “shut down” in the second paragraph with “as intended to isolate.”</p> <p>Response: See Example 2b in the Application Guidelines under the Misoperation category 2 (Failure to Trip – Other Than Fault) discussion. Change made.</p> <p>AEP recommends adding generation examples of both a normal time delay operation and a misoperation to category 3 of the application guidelines.</p> <p>Response: Alternatively, the drafting team revised the definition of Misoperation category 3 (Slow Trip – During Fault) for clarity. Changed made.</p>

Organization	Yes or No	Question 4 Comment
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
Liberty Electric Power LLC	No	<p>Agree with the comments of the Standards Development Team of the North American Generator Forum, which state:</p> <p>The standard should completely exclude operation of reverse power relays when shutting-down units, or (better) classify such devices as not being part of Protection Systems (they do not protect BES equipment; they prevent turbine mechanical damage). This subject is discussed in the Application Guidelines (p.17), but the distinction attempted between control and protection functions of reverse power relays is obscure.</p>
<p>Response: The drafting team thanks you for your comment. According to the IEEE Guide for AC Generator Protection (C37.102-2006), Section 4.5.5 (Motoring), sub-section 4.5.5.6 (Tripping mode), “Primary motoring protection is provided by reverse power relays for all unit types.” Reverse power relays, by definition, are a Protection System and cannot be categorically excluded. Because reverse power relays provide motoring protection, the drafting team has provided an exclusion in the Applicability of the standard. Also, this exclusion is clarified in the Application Guidelines concerning the relay’s use as a control function for shutting down a unit and as anti-motoring protective protection for a generating unit. Change made.</p>		
Idaho Power Company	No	Only a request that the application guidelines be maintained with the final version of the standard.
<p>Response: The drafting team thanks you for your comment. The Application Guidelines will remain part of the standard. Change made.</p>		
Los Angeles Department of Water and Power	No	Please see answer to Question 5
<p>Response: The drafting team thanks you for your comment; and refers to the response provided in Question 5.</p>		
Dominion	No	The addition of the word “composite” adds nothing to the existing term Protection System and in fact introduces confusion. Dominion assumes a Missoperation occurs

Organization	Yes or No	Question 4 Comment
		only if all protection (primary, secondary, backup, pilot and non-pilot relay schemes) failed to operate as intended. If this assumption is incorrect, please clarify.
<p>Response: The drafting team thanks you for your comments. The composite Protection System is the collective operation of the entire Protection System for an Element which is included in determining whether a Misoperation occurred. To clarify the usage of the terminology, the drafting team is proposing the definition “Composite Protection System” which has an exclusion for backup protection provided by a remote Protection System. Change made.</p>		
Texas Reliability Entity	No	The first paragraph of the Guidelines and Technical Basis defines the composite protection system to include the backup protection. This needs to be clearly defined as “local backup” only and not to include remote backup protection.
<p>Response: The drafting team thanks you for your comments. The composite Protection System is the collective operation of the entire Protection System for an Element which is included in determining whether a Misoperation occurred. To clarify the usage of the terminology, the drafting team is proposing the definition “Composite Protection System” which has an exclusion for backup protection provided by a remote Protection System. Change made.</p>		
Tennessee Valley Authority	No	The PRC-004-3 requirements’ rationale for each requirement (gray boxes next to each requirement) and the Guidelines and Technical Basis (at the end of the document) are well thought out and contain significant justification and logic for each standard requirement. Recommend either keeping this information attached to the standard or formalizing it into a reference document that will will be easily accessible to the electric power industry. There was no indication in the draft standard as to the repository of this significant information.
<p>Response: The drafting team thanks you for your comment. The rationale boxes will be moved to the Application Guidelines portion of the standard upon industry approval and remains with the standard. No change made.</p>		
Madison Gas and Electric Company	No	Under R4 there is confusion when the words "complete" is used. It should be stated (here and in the requirement) that an entity can extend the 180 days to complete if they have supporting documentation, i.e., parts on order, work orders, etc.

Organization	Yes or No	Question 4 Comment
<p>Response: The drafting team thanks you for your comment. The Application Guidelines have been clarified not to infer the implementation of the CAP must be completed in 180 days (See draft 3, page 20 "...and requires the CAP implementation be less than 180 days."). The CAP has its own timetable which is required to be updated by the entity when actions or timetables change. Change made.</p>		
Colorado Springs Utilities	No	
Northeast Power Coordinating Council	No	
Southwest Power Pool Reliability Standards Development Team	No	
City of Tacoma, Tacoma Public Utilities	No	
Bonneville Power Administration	No	
PacifiCorp	No	
Arizona Public Service Company	No	
Operational Compliance	No	
Georgia Transmission Corp	No	
Xcel Energy	No	

Organization	Yes or No	Question 4 Comment
Public Service Enterprise Group	No	
Manitoba Hydro	No	
Tri-State G&T	No	
Wisconsin Electric Power Company	No	
Sacramento Municipal Utility District	No	
ReliabilityFirst	No	
City of Tallahassee	No	
Northeast Utilities	No	
Entergy Services, Inc. (Transmission)	No	
Ingleside Cogeneration LP	No	
ExxonMobil Research and Engineering	No	
City of Tallahassee	No	
City of Tallahassee - Electric Utility	No	

Organization	Yes or No	Question 4 Comment
Hydro-Québec Procution	No	
Public Service Company of New Mexico	No	
ITC Holdings	Yes	We have no issues with the guidelines, provided there is clarification that the guidelines are not to be used to support audit data request or findings.
<p>Response: The drafting team thanks you for your comment. The Measures are used to support performance with the Requirements. The Application Guidelines are not enforceable. No change made.</p>		
SERC Protection and Controls Subcommittee	Yes	<p>1) Unknown / unexplainable is the ‘cause’ of about 12% of Misoperations per NERC reports. An R3 ‘no further action’ declaration example would be helpful. Perhaps your ‘no action plan’ declaration example on page 23 was intended for this. If so, please so state there.</p> <p>Response: In the Application Guidelines, see the last paragraph of the section Requirement R5 (previously R3) which notes a declaration that no further corrective actions will be taken is expected to be used sparingly. No change made.</p> <p>2) Please replace ‘reverse power’ with ‘overexcitation’ on page 15 in the failure to operate for a non-fault condition section. Reverse power relays are usually excluded so the example is confusing as is.</p> <p>Response: The Application Guidelines (Failure to Trip – Other Than Fault) have been clarified. Example 2b replaced “reverse power” with “over excitation.” Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
City of Austin dba Austin Energy	Yes	<p>Austin Energy (AE) recommends the following changes in the Guidelines and Technical Basis section:</p> <p>(1) Remove the reference of reverse power relaying from item #2. This reference can</p>

Organization	Yes or No	Question 4 Comment
		<p>be confusing because the protection scheme is used for safe shutdown of a generating unit. A substitute example would be “A failure of a “primary” loss of field relay is not a failure to trip Misoperation as long as another component of the generator’s composite Protection System operated to shut down the generator.”</p> <p>Response: The Application Guidelines (Failure to Trip – Other Than Fault) have been clarified. Example 2b replaced “reverse power” with “over excitation.” Change made.</p> <p>(2) References to generator Protection Systems that are exempt should be removed and placed in the opening section similar to the exclusions used to exempt circuit breaker and other interrupting device mechanisms. AE believes this would clarify what relay systems are excluded before reading the parts of the definition and requirements.</p> <p>Response: The Application Guidelines have been revised for clarity by grouping topics. See the heading “Special Cases.” Change made.</p> <p>(3) The second paragraph on page 26 of the redline, which reads “With the ultimate goal of keeping the implementation time of a CAP as short as possible, if a cause of a Misoperation is determined quickly the CAP creation timeframe (60 days) becomes applicable and requires the CAP implementation be less than 180 days” is not consistent with the Standard Requirements and should be removed. The standard requires CAP development within 180 days, not CAP implementation or completion in 180 days.</p> <p>Response: The Application Guidelines have been clarified not to infer the implementation of the CAP must be completed in 180 days (See draft 3, page 20 “...and requires the CAP implementation be less than 180 days.”). The CAP has its own timetable which is required to be updated by the entity when actions or timetables change. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
Exelon Corporation and it’s	Yes	Exelon would like additional clarification added to the Application Guide regarding the inclusion of CAP corrective actions for addressing the application of the CAP to other

Organization	Yes or No	Question 4 Comment
affiliates		<p>Protection Systems owned by the utility. Specifically, the Guide should address that such a CAP can be considered complete once a program (required to address application of the CAP to other Protection Systems) is developed. Example 2 in the Application Guide exemplifies this notion.</p> <p>Additionally, application of the CAP to other Protection Systems owned by the utility should be considered fulfilled if an existing program (such as Protection System maintenance and testing practices) fulfill the actions necessary to address such a CAP.</p>
<p>Response: The drafting team thanks you for your comment. Examples have been provided in the Application Guidelines to illustrate the evaluation of the entity’s other Protection Systems including other locations within the CAP. The CAP is not complete until all actions in the CAP are satisfied. An entity may create an action within a CAP in which it states that a program outside the CAP will be used to address similar issues at other locations. In this case the CAP is not declared complete until the program is developed. See Example R6b in the Application Guidelines. Change made.</p>		
Pepco Holdings Inc & Affiliates	Yes	<p>On page 18 of the Guidelines and Technical Basis section it states “Requirement R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection System. The drafting team believes the owner of the BES interrupting device that operated would be in the best position to analyze the Protection System Operation, determine if a Misoperation occurred, and perform the initial investigation to determine the cause of the Misoperation.” Furthermore, on page 19 it states “Regardless of whether a cause is identified, the BES interrupting device owner must document the investigation ...”Based on the arguments presented in our response to Question 2 we vigorously disagree with this assertion. When a Protective System operates, a means is provided to determine which protective component initiated the trip (i.e., relay targets, lockout relay operations, microprocessor relay event logs, etc.) The owners of these Protective System devices, which initiated the trip of the interruption device, are much better suited to investigate the cause of the Protective System operation than the owners of the interrupting device. In addition, all previously approved versions of PRC-004 rightly place the responsibility for reviewing and analyzing Protective System operations on the owners</p>

Organization	Yes or No	Question 4 Comment
		<p>of the Protective Systems, not the owners of the interrupting device. The interrupting device is, by definition, not even a component of a Protective System. We agree that if the owner of the relay that initiated the trip does not own all the remaining components of the associated Protection System (i.e., CTs or VT's) they may require assistance and support from the owners of those additional components to complete their analysis. However, the owner of the Protective System that initiated the trip should be the party responsible for analyzing if a protective system misoperation occurred. If in the course of that investigation they determine the cause was attributed to a component of the Protection System which they did not own (such as a blown VT fuse owned by others), they should notify the other party, who would in turn be responsible for appropriate corrective action. In conclusion, nowhere in this standard should compliance responsibility be assigned to the owner of an interrupting device.</p>
<p>Response: The drafting team thanks you for your comment. 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. Requirement R1 was revised to bring clarity to the obligations of each applicable entity. Change made.</p>		
Rayburn Country Electric Cooperative	Yes	<p>Prefer the term "entire" to "composite" again for clarity sake since entire seems more intuitive in nature rather than composite which requires some analytical thought to apply it.</p> <p>Example, a transformers entire protection system is slow to operate.</p> <p>Versus, a transformers composite protection system is slow to operate.</p>
<p>Response: The drafting team thanks you for your suggestion. The drafting team is proposing a definition for the term "Composite Protection System." Change made.</p>		
Duke Energy	Yes	See our comment above on Question #1. The following paragraph should be deleted

Organization	Yes or No	Question 4 Comment
		<p>from the accompanying Guidelines and Technical Basis section:</p> <p>“The reference to the TPL standards is meant to place some bounds on the time to clear a Fault and prevent dynamic instability. The performance requirements in the TPL standards are found in Table 1, and are applicable to all contingencies mentioned for Type A, B and C contingencies.”</p>
<p>Response: The drafting team thanks you for your comments. The reference to the TPL standards in both the Misoperation definition and body of the standard has been removed. Change made.</p>		
<p>Southern Company - Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Mississippi Power Company; Gulf Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing</p>	<p>Yes</p>	<p>Southern Company supports the SERC comments and are including the following additional comments:</p> <ol style="list-style-type: none"> In various locations of the text, Protection System misoperations are discounted as misoperations for situations where other redundant protection may have adequately operated. In these instances, perhaps the classification should be changed to non-reportable misopeartion rather than simply that they are not misoperations (we believe that they are still misoperations). We believe that entities should be allowed to determine whether or not the Protection System operated appropriately. This is inherent in our suggested simpler definition of Misoperation through including "than intended". <p>Response: The composite Protection System is the collective operation of the entire Protection System for an Element which is included in determining whether a Misoperation occurred. To clarify the usage of the terminology, the drafting team is proposing the definition “Composite Protection System” which has an exclusion for backup protection provided by a remote Protection System. Change made.</p> <ol style="list-style-type: none"> In the text for section 6 of the Misoperation definition, we disagree with the phrase "An operation that occurs during a non-fault condition but was initiated by on-site maintenance, testing, inspetion, construction or commissioning is not a Misoperation." This is obviously an unnecessary trip - other than fault. This should be included in a list of non-reportable misoperations.

Organization	Yes or No	Question 4 Comment
		<p>Response: The on-site maintenance exception in the Misoperation definition, Unnecessary Trip – Other Than Fault (category 6) was added during the draft 2 development of the standard based on industry comment. An operation due to on-site maintenance would not be a Misoperation; therefore, not reportable. No change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>		
Nebraska Public Power District	Yes	<p>The drafting team should review the BES Definition drafting team documents and evaluated how it relates to misoperations. It would be desirable to avoid any disconnects or conflicts between these definitions and standards. Some BES Definition drafting team documents indicate individual wind turbine generators are part of the BES. Is misoperation data desired down to this level? During Webinars explaining the BES definition documentation questions were asked regarding how the BES documentation helps identify or determine what protection systems are included for PRC-005. The BES drafting team stated that protections systems for PRC-005 are not to be defined by the equipment identified in the BES definitions documentation but instead are to be defined the PRC-005 standard and documentation. Would this be the case for PRC-004-3 as well?</p>
<p>Response: The drafting team thanks you for your comment. This standard applies to Protection Systems for BES Elements in achieving its goal to identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements. Entities will apply the BES definition to determine applicability to its Protection Systems. No change made.</p>		
Midwest Reliability Organization NERC Standards Review Forum (NSRF)	Yes	<p>The NSRF appreciates the addition of the Application Guide at the end of the Standard. The Application Guide will help NERC, the Regional Entities and Registered Entities to move away from a zero defect CMEP process.</p>
<p>Response: The drafting team thanks you for your comment.</p>		
PPL NERC Registered Entities	Yes	<p>The standard should completely exclude operation of reverse power relays when</p>

Organization	Yes or No	Question 4 Comment
		<p>shutting-down units, or (better) classify such devices as not being part of Protection Systems (they do not protect BES equipment; they prevent turbine mechanical damage). This subject is discussed in the Application Guidelines (p.17), but the distinction attempted between control and protection functions of reverse power relays is obscure.</p>
<p>Response: The drafting team thanks you for your comment. According to the IEEE Guide for AC Generator Protection (C37.102-2006), Section 4.5.5 (Motoring), sub-section 4.5.5.6 (Tripping mode), “Primary motoring protection is provided by reverse power relays for all unit types.” Reverse power relays, by definition, are a Protection System and cannot be categorically excluded. Because reverse power relays provide motoring protection, the drafting team has provided an exclusion in the Applicability of the standard. Also, this exclusion is clarified in the Application Guidelines concerning the relay’s use as a control function for shutting down a unit and as anti-motoring protective protection for a generating unit. Change made.</p>		
Essential Power, LLC	Yes	<p>The standard should completely exclude operation of reverse power relays when shutting-down units, or (better) classify such devices as not being part of Protection Systems (they do not protect BES equipment; they prevent turbine mechanical damage). This subject is discussed in the Application Guidelines (p.17), but the distinction attempted between control and protection functions of reverse power relays is obscure.</p>
<p>Response: The drafting team thanks you for your comment. According to the IEEE Guide for AC Generator Protection (C37.102-2006), Section 4.5.5 (Motoring), sub-section 4.5.5.6 (Tripping mode), “Primary motoring protection is provided by reverse power relays for all unit types.” Reverse power relays, by definition, are a Protection System and cannot be categorically excluded. Because reverse power relays provide motoring protection, the drafting team has provided an exclusion in the Applicability of the standard. Also, this exclusion is clarified in the Application Guidelines concerning the relay’s use as a control function for shutting down a unit and as anti-motoring protective protection for a generating unit. Change made.</p>		
Cogentrix Energy Power Management, LLC	Yes	<p>The standard should completely exclude operation of reverse power relays when shutting-down units, or (better) classify such devices as not being part of Protection Systems (they do not protect BES equipment; they prevent turbine mechanical damage). This subject is discussed in the Application Guidelines (p.17), but the</p>

Organization	Yes or No	Question 4 Comment
		distinction attempted between control and protection functions of reverse power relays is obscure.
<p>Response: The drafting team thanks you for your comment. According to the IEEE Guide for AC Generator Protection (C37.102-2006), Section 4.5.5 (Motoring), sub-section 4.5.5.6 (Tripping mode), “Primary motoring protection is provided by reverse power relays for all unit types.” Reverse power relays, by definition, are a Protection System and cannot be categorically excluded. Because reverse power relays provide motoring protection, the drafting team has provided an exclusion in the Applicability of the standard. Also, this exclusion is clarified in the Application Guidelines concerning the relay’s use as a control function for shutting down a unit and as anti-motoring protective protection for a generating unit. Change made.</p>		
Kansas City Power & Light	Yes	There are some examples of CAP in the document. Adding examples relative to my comment in question 5 would be beneficial.
<p>Response: The drafting team thanks you for your comments. The comment in Question 5 (“Explain in a declaration why corrective actions are beyond the entity’s control or would not improve BES reliability...”) contains an example and discussion that was previously addressed in the Application Guidelines under Requirement R2 in the last paragraphs. No change made.</p>		
Luminant Power	Yes	<p>Luminant recommends the following changes in the Guideleins and Technical Basis section.</p> <p>1) Remove the reference of reverse power relaying from item #2. This reference can be confusing since the protection scheme is used for safe shutdown of a generating unit. An substitute example would be “A failure of a “primary” loss of field relay is not a failure to trip Misoperation as long as another component of the generator’s composite Protection System opertated to shut down the generator.”</p> <p>Response: Change made.</p> <p>2) References to generator Protection Systems that are exempt should be removed and placed in the opening section similar to the exclusions used to exempt circuit breaker and other interrupting device mechanisms. Luminant believes that this would clarify what relay systems are excluded before reading the parts of the definition and</p>

Organization	Yes or No	Question 4 Comment
		requirements. Response: A section called “Special Cases” has been added to the Application Guidelines. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Mary Jo Cooper	Yes	
ISO RTO Council Standards Review Committee	Yes	
seattle city light	Yes	
American Transmission Company, LLC	Yes	
Ameren	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Independent Electricity System Operator	Yes	
Oncor Electric Delivery Company LLC	Yes	

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

Summary Consideration:

The following resulted in a revision to the proposed standard. Many of the comments here were also summarized above. These are the most significant comment themes that resulted in a change to the proposed standard. They are summarized here and may be duplicative of other summaries:

At least another five comments supported by about 17 individuals raised questions concerning the action plan of investigative actions. Requirement R1 now includes identification of Misoperation and determination of a cause. If a cause is not readily apparent, further investigative actions may be undertaken (Requirement R4) until a cause is determined or a declaration of no cause can be determined. The concept of an action plan has been eliminated from the standard.

About five comments supported by ten stakeholders requested clarity concerning time periods or Protection System owner's responsibilities. The result was that the drafting team revised Requirement R1 to provide clarity on each Protection System owners' responsibilities following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components, time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation.

Approximately two comments represented by 17 individuals raised questions concerning the data request. The NERC Rules of Procedure, Section 1600 Request for Information or Data (i.e., Data Request) will dictate the specific entity (i.e., Protection System component owner) that is to report a Misoperation and the format for reporting. Reporting under the standard will end.

At least two comments supported by about 13 individuals asked for clarification on the use of "BES interrupting device." The drafting team has clarified the use in the standard's Application Guidelines under the "Definitions" section.

The following did not result in a change to the proposed standard. This next summary lists the most significant themes of these comments that did not result in a change to the proposed standard. They are summarized here and may be duplicative of other summaries:

Approximately seven comments supported by 26 stakeholders addressed the topic of internal controls. The drafting team continues to support the proposed standard as currently structured. The draft requirements allow Compliance Enforcement Authority (CEA) to take into account use of internal controls in connection with monitoring activities. However, internal controls are only a mechanism to help auditors determine the depth and breadth of testing as it pertains to compliance with the related

Reliability Standard and specific requirements and when necessary understand the facts and circumstances of instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process.

About three comments representing at least 22 individuals mentioned having a Reliability Standard Audit Worksheet (RSAW). The drafting team anticipates posting a draft PRC-004-3 RSAW so that entities will have an opportunity to consider auditing approaches. Posting is expected mid-way through the draft 4 posting of PRC-004-3.

At least four comments supported by 13 stakeholders requested clarity about the Corrective Action Plan (CAP). The drafting team noted that the NERC Glossary definition of Corrective Action Plan includes the phrase “remedy a specific problem”. In the context of this standard, the “problem” is the cause a Misoperation. Mitigating actions may be included as a part of the CAP.

About four comments supported by at least ten individuals suggested alternatives to make the standard less burdensome using metrics. One of the objectives of this project is to bring consistency to metrics through the Section 1600 data request. In conjunction with data reporting, the proposed definition of Misoperation will improve identifying the appropriate category of Misoperation. The drafting team agrees that a results-based approach using metrics could simplify the standard and reduce compliance burdens; however, it may take several years of data collection to develop consistent and meaningful metrics for measure performance.

Two comments were concerned about the slow trip category of the Misoperation definition as it pertains to having the ability to measure a slow operation. This includes having Disturbance Monitoring Equipment (DME) and the compliance approach.

The remaining comments were individual in nature; please see the individual comments for detail.

Organization	Question 5 Comment
City of Austin dba Austin Energy	(1) For events where a BES breaker operates but the Registered Entity does not own all of the Protection Systems, it is possible the other owner would not be notified until 120 days has elapsed. This is counter the the expectation of the drafting team that “it is expected that both entities will work together to investigate the cause of the operation.” Austin Energy (AE) recommends re-writing the bullets of R1 to require notification within a set number of days (AE recommends 15 calendar days) and then require the entities to work together as necessary. AE provides language revisions for

Organization	Question 5 Comment
	<p>consideration:</p> <p>R1.1. Within 120 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation.</p> <p>--If the entity owns both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation.</p> <p>--If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, notify the other owner(s) of the Protection System component(s) within 15 calendar days.</p> <p>--The BES interrupting device and Protection System component owner(s) notified by the BES interrupting device owner shall work together to determine if there was a correct operation or a Misoperation of their component.</p> <p>Response: Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.</p> <p>(2) By using the definition of a Corrective Action Plan (CAP) in the NERC Glossary of terms, it is unclear what differences exist between a CAP and an Action Plan in the standard. They may appear to be the same. AE believes the intent of the action plan is to document an investigation plan, so recommends that additional language be added to the Rationale box for R2 that describes the intent of a CAP (as Corrective Action to avoid future recurrence) and an action plan as an investigation or other non-Corrective plan of action to investigate the cause of a misoperation or to determine if a misoperation has occurred.</p>

Organization	Question 5 Comment
	<p>Response: Action plan has been removed from the Standard and replaced with investigative actions in R4. CAP development is covered by Requirement R5 and CAP implementation by Requirement R6. Change made.</p> <p>(3) AE appreciates the efforts of the Standard Drafting Team and supports the goal of keeping the misoperation identification and correction processes as short as possible. There can be cases where extra time is necessary and the entire process may take longer than 180 days. The Standard allows for these extreme cases as written, assuming an action plan allows for the additional investigation of an operation or misoperation. For instance, if the cause of a misoperation cannot be identified, the entity may create an action plan to further research/analyze the cause (possibly the entity must ship equipment back to the OEM for cause determination). Once the cause is identified, then the Corrective Action Plan must be developed within 60 days. AE recognizes, and agrees with the Standard Drafting Team’s intent to ensure active analysis and appropriate corrective actions are adequately considered and/or implemented. Although it is likely there is sufficient time to analyze operations, identify misoperations and take corrective action for most events within the standard as written, there is a significant administrative burden involved to demonstrate action plans and/or corrective action plans are developed within the proper timelines. Therefore, although AE believes the timelines are workable as written, AE provides the following alternative recommendation. Remove all of the required timelines and instead require the investigation/action plans and Corrective Action Plans only. These action plans and Corrective Action Plans contain timelines that must be followed by their very nature.</p> <p>Response: The timelines within the standard provide the entity a period of time from the BES interrupting device operation to identify any potential Misoperation and its cause. For cases where an entity needs to perform additional investigation beyond 120 calendar days, the drafting team added a proposed Requirement R4 which provides the entity a mechanism to continue investigative actions by documenting its progress within established periods. The owner of the Protection System components that Misoperated has the ability to establish its own timetables within each CAP. The</p>

Organization	Question 5 Comment
	<p>requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation identification, determining the cause, and the development and implementation of the CAP. The associated dates and timetables allow the Requirements to be measurable. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
<p>Ameren</p>	<p>(1) Please clarify the sentence on page 17, the second to last paragraph, "Protection System operations unrelated to on-site maintenance, testing, inspection, construction or commissioning activities which occur with the protected Element out of service, that trip any in-service Elements are Misoperations" by putting it in a new paragraph and including some examples. Does the protected Element have to be out of service? Is this intended to include human error (e.g. bumping the panel) caused trips by personnel other than Protection System maintenance personnel?</p> <p>Response: It is important to emphasize that the maintenance exclusion is for active maintenance. A remote-end trip is included in the existing exclusion if it resulted from "on-site" activities at a different location. The Application Guidelines have also been enhanced with an example (6d) related to this topic. Change made.</p> <p>An example of an "Element out of service" would be a breaker that is switched out of service with the breaker disconnects open. If the breaker failure scheme operates due to a problem with the scheme, several in-service Elements could be tripped. No change made.</p> <p>(2) Please add "completed" on page 20, near the bottom, so that the title reads " The following are examples of completed Corrective Action Plans (CAPs):"</p> <p>Response: The word "completed" was incorporated into the text discussing the completed CAPs. See the examples under Requirement R6 in the Application Guidelines. Change made.</p> <p>(3) In addition to our comments, we also agree with the SERC Protection & Control</p>

Organization	Question 5 Comment
	<p>Subcommittee (PCS) comments and include them by reference.</p> <p>Response: Please see the response to the SERC Protection & Control Subcommittee (PCS).</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
<p>ACES Standard Collaborators</p>	<p>(1) We recommend introducing the term “BES interrupting device” as a new definition with clearly defined parameters.</p> <p>Response: The use of “BES interrupting device” has been clarified in the standard’s Application Guidelines under the “Definitions” section. Change made.</p> <p>(2) We would like more information on the Section 1600 data request for Misoperation data. Also, if a data request is going to be utilized, will registered entities still need to continue reporting under PRC-004-2? This would be a redundant process and we encourage NERC to coordinate the timing of the data request to take the place of the current reporting requirements.</p> <p>Response: The NERC Rules of Procedure, Section 1600 Request for Information or Data (i.e., Data Request) will dictate the specific entity (i.e., Protection System component owner) that is to report a Misoperation and the format for reporting. Reporting under the standard will end. No change made.</p> <p>Further, we disagree with the evidence retention section of this standard. TO, GO, and DP are audited on a six-year cycle, which is too long of a timeframe to retain evidence. We suggest shortening the amount of time to three years, unless there is an open or ongoing investigation, action plan, or CAP. If there is a section 1600 data request, why does the data need to be retained? NERC already has the information.</p> <p>Response: The Evidence Retention section has been revised using the Drafting Team Guidelines guidance for evidence retention that was endorsed by the Standards Committee, April 2009. All requirements have been reduced to 12 calendar months as the minimum retention period according to standard drafting guidelines. Change made.</p>

Organization	Question 5 Comment
	<p>The drafting team removed the reporting obligations from the standard and is working with NERC staff to develop a data request under Section 1600 of the NERC Rules of Procedure. The drafting team notes that the standard and data request have been developed in a manner such that evidence used for compliance of the standard and data request are intended to be independent of each other. The 1600 data request does not eliminate the need to retain PRC-004 data. The data request will be submitted for approval at the time the revised standard is submitted. Data retention is included as part of the standard because it is essential for auditing compliance with the standard. No change made.</p> <p>(3) This standard is another candidate for implementing internal controls, and should not contain “zero-defect” language. For example, an entity should be able to have controls in place to determine whether Misoperations are being identified, assessed and corrected. This is the essence of PRC-004-3, and therefore should be revised to include these concepts. There should not be zero-defect penalties if an entity has controls to catch errors and fix them. Currently, the standard would penalize an entity for each instance of noncompliance.</p> <p>Response: The drafting team continues to support the proposed standard as currently structured. The draft requirements allow Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities. However, internal controls are only a mechanism to help auditors determine the depth and breadth of testing as it pertains to compliance with the related Reliability Standard and specific requirements and when necessary understand the facts and circumstances of instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process. No change made.</p> <p>(4) We continue to be confused by the interaction of Requirements R1 and R3. While R1 does not compel the protective relay owner to identify the cause of a Misoperation, it does compel the owner to investigate the Misoperation. One would presume an auditor would expect investigative actions conducted for Requirement R1 to be</p>

Organization	Question 5 Comment
	<p>reasonable. However the application guidelines section for Requirement R3 states clearly on page 14 that this requirement only applies if “reasonable investigative actions have not been exhausted”. Thus, it would appear that Requirement R3 could never apply without a violation of Requirement R1 Part 1.2. We think the interaction of these requirements need further clarification. Furthermore, we suggest that Requirement R3 could actually be made part of Requirement R1 which would help alleviate the confusion. For example, Part 1.2 could have a subpart that states that an action plan should be developed for any reasonable investigative actions that may require more than 120 days to complete. Another part could be to document why the cause cannot be identified.</p> <p>Response: This has been clarified by the new Requirement R1 (and R3) that requires the identification of Misoperation which is typically when the entity will determine the cause. If a cause is not identified, further investigative actions must be taken (see new Requirement R4) until a cause is determined or a declaration of no cause is made. The concept of an action plan has been eliminated from the standard. Change made.</p> <p>(5) Since UVLS is specifically excluded in the applicability section does it make sense to include it under voltage conditions in part 2 and 4 of the Misoperation definition?</p> <p>Response: There are other Protection Systems that trip for undervoltage conditions besides UVLS. No change made.</p> <p>(6) Why can't the implementation requirement R4 be included as a Part of the other requirements? Furthermore, it is questionable if it is even needed for FERC has stated in past orders that there is an implied obligation to implement plans, policies and procedures when a requirement compels their development. This requirement is similar to the types of standards that would be subject to Paragraph 81.</p> <p>Response: Placing the implementation in a separate requirement makes it more visible and makes it a separate compliance element. No change made.</p> <p>(7) Thank you for the opportunity to comment.</p>

Organization	Question 5 Comment
	Response: Thank you for your comments.
Response: The drafting team thanks you for your comments; please see the above responses.	
Madison Gas and Electric Company	<p>: (1) As written in R1.1, if a BES generator’s normal shut down cycle is caused by a Protection System operation (a set trip point in the relay) then each shut down would be required to be “identified and reviewed”. This is similar to issues that a generator operator has under Project 2011-INT-02 AVR control during start up and shut down. MGE recommends that either a footnote be provided to address the exclusion of normal shut down processes or add another bullet excluding a generators normal shut down processes where the unit’s breaker is activated via a set point within the Protection System (i.e., relay).</p> <p>Response: The drafting team has provided additional detail concerning the use of protection and control functions for generators in the Application Guidelines regarding reverse power relays. The proposed standard’s Applicability excludes certain intended uses of protection functions as control functions. Change made.</p> <p>(2) R4 could be viewed as allowing for CAPs to be extended beyond 180 days (the maximum days in the combination of R1 and R2). If this is the intent of the SDT, then clearly state this within the requirement. As written, an entity could be in violation of the maximum time frame of 180 days by extending the CAP under R4.</p> <p>Response: The Application Guidelines have been clarified not to infer the implementation of the CAP must be completed in 180 days (See draft 3, page 20 “...and requires the CAP implementation be less than 180 days.”). The CAP has its own timetable which is required to be updated by the entity when actions or timetables change. Change made.</p>
Response: The drafting team thanks you for your comments; please see the above responses.	
Dominion	: (1) Suggest the Implementation Plan be modified under the Applicability section as

Organization	Question 5 Comment
	<p>indicated below:</p> <p>This standard applies to the following Facilities: Protection Systems for BES Elements. Underfrequency Load Shedding (UFLS) that trips a BES Element This standard does not apply to the following Facilities: The flowing Special Protection Systems (SPS), Remedial Action Schemes (RAS), and Undervoltage Load Shedding (UVLS) Non-protective functions that may be imbedded within a Protection System</p> <p>Response: The exclusion language concerning SPS and RAS in the previous posting has been removed from the Applicability and added to the rationale. Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are not included in this version of the standard because they will be handled in the second phase of this project. UVLS is covered by PRC-022-1 under Project 2008-02 – Undervoltage Load Shedding. Change made.</p> <p>(2)Suggest the Mapping Document be modified under the Proposed Language in PRC-004-3 column as indicated below:</p> <p>4.2.1 Protection Systems for BES Facilities, Facilities needs to be replaced with Elements.</p> <p>Response: The mapping document has been corrected to be consistent with the standard. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
<p>SERC Protection and Controls Subcommittee</p>	<p>(1) Some entities presently use their PRC-004 reporting as a means of documenting CAPs. They may prefer to use your proposed data request under Section 1600 of the NERC Rules of Procedure for these purposes. Please change page 5 wording to “The data submitted as part of the data request will not be used by NERC or the Regions for compliance or enforcement purposes.”</p> <p>Response: The sentence, “The data submitted as part of the data request will not be used for compliance or enforcement purposes” has been removed because the drafting</p>

Organization	Question 5 Comment
	<p>team does not have this authority. The drafting team notes that the standard and data request have been developed in a manner such that evidence used for compliance of the standard and data request are intended to be independent of each other. Change made.</p> <p>(2) Compliance section 1.2 on page 9 states “The Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System shall keep data or evidence to show compliance with Requirements R1, R2, R3, and R4 and Measures M1, M2, M3, and M4, since the last audit unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.” Please delete “and Measures M1, M2, M3, and M4” because entities must comply with Requirements, but Measures are not allowed to expand that scope.</p> <p>Response: The reference to each Measure under Section 1.2 – Evidence Retention is consistent with the standard drafting guidelines. No change made.</p> <p>(3) In the first sentence of R2 on page 7, please add “first” before “cause” so it reads “Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 60 calendar days of identifying the first cause of each Misoperation: ...” Pages 19 and 20 make it clear that this is triggered by the first cause, but some entities may miss this application guidance.</p> <p>Response: The word “first” has been included. Change made.</p> <p>(4) Please include ‘Composite Protection System’ as a defined term that remains with this standard (similar to PRC-005-2 approach for Component, Component Type, etc.). Your definition on page 14 is fine, but move it up to just after the page 3 Definitions. Regarding comments for all questions 1-5 above:</p> <p>Response: The composite Protection System is the collective operation of the entire Protection System for an Element which is included in determining whether a Misoperation occurred. To clarify the usage of the terminology, the drafting team is proposing the definition “Composite Protection System” which has an exclusion for backup protection provided by a remote Protection System. Change made.</p>

Organization	Question 5 Comment
	<p>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.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
<p>Seminole Electric</p>	<p>1. The Proposed PRC-004-3 combines PRC-004-2a and PRC-003-1. This project is applicable to a “Distribution Provider” whereas PRC-004-2a is applicable to a “Distribution Provider that owns a transmission Protection System.” Does the STD believe that the additional caveat should be added to the Distribution Provider (DP) applicability, i.e., that the DP need to own a transmission Protection System?</p> <p>Response: Applicability 4.2.1 specifies that PRC-004-3 is applicable to Protection Systems for BES Elements; therefore, the reference is not necessary. No change made.</p> <p>2. In the “Purpose/Industry Need” section that the STD developed for this Project, the STD states that because PRC-003-1 was never approved by the Commission, “there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2... This could lead to a potential reliability gap.” (Emphasis added). This infers that there is a need for some form of standardized regional mitigation requirements. When NERC drafted PRC-003-1, NERC made RROs the applicable entity in order for each RRO to “establish, document and maintain is procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations.” (See R1. of PRC-003-1). However, in the proposed action, PRC-004-3 does not appear to require any such regional processes for misoperations mitigation. In fact, the new proposed Standard is not even applicable to RRO as the new standard does not require the RRO to perform any action. It does not appear that the new draft Standard mitigates the deficiency left by the non-approval of PRC-003-1 and so this should be addressed via the addition of some form of regional analysis requirement.</p> <p>Response: This standard or any NERC Reliability Standard cannot place any requirements on the Regional Entity. The proposed PRC-004-3 standard addresses</p>

Organization	Question 5 Comment
	mitigation through the development of the CAP to correct the cause(s) of Misoperations. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
ReliabilityFirst	<p>Although this draft of the standard is considered a Results-Based Standard it is difficult to see how the requirements are written to achieve a measurable outcome associated with reaching a level of reliability performance, a reduction in reliability risk or a necessary level of competency. This draft standard instead appears to be administrative in nature that is more concerned with creating documentation solely for compliance purposes. The following are specific issues or suggestions:</p> <p>1) the standard contains extra 120 day and 60 day deadlines that do not provide reliability benefit. Although there is value in investigating Misoperations quickly, it is more important to fix the problem and prevent its reoccurrence.</p> <p>Response: Identifying Protection System Misoperations then determining and rectifying their causes will improve reliability. The time frames stated within the standard are maximum times, not minimum. An entity should resolve Misoperations as quickly as possible. However, due to the possibility of seasonal peaks in operations it was deemed necessary to provide for ample time to review large numbers of operations and schedule the outages sometimes necessary for investigations. No change made.</p> <p>2) Late identification of Misoperations will be a violation even if they are not particularly significant. Specifically, Misoperations that occur with no Fault present may not be readily apparent. The deadlines in the standard could cause disincentives to fully investigate Protection System performance because it may result in compliance violations.</p> <p>Response: Prompt identification of a Misoperation is important regardless of its perceived significance. Identifying a Misoperation and its cause(s) leads to preventing reoccurrence which, without correction, could lead to a reduction in reliability. Additionally, the identification of a Misoperation cause leads the entity to considering</p>

Organization	Question 5 Comment
	<p>its other Protection Systems including other locations which may result in identifying and correcting a potential problem with another Protection System which may be significant to reliability. The standard provides options for entities to explain why actions were not taken. No change made.</p> <p>Response: Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.</p> <p>3) The standard provides no means of ensuring that Misoperations are addressed by CAPs on a timely basis. Of particular concern is failure to trip (- during Fault) type Misoperations. The cause for this type of Misoperation should be either mitigated or the CAP completed in less 12 months.</p> <p>Response: The scope of a CAP can vary greatly depending on whether the entity chooses to implement a CAP to correct a single cause or multiple causes (e.g., including other locations); therefore, the risk prioritization and timetable to complete the CAP is at the discretion of the entity. No change made.</p> <p>4) It is suggested that the drafting team embrace a reliability performance based approach that would fit into the results-based philosophy. Specifically, adherence to the standard should be based on achieving or surpassing certain metrics such as Misoperation rate, the percent of causes unidentified (Unknowns/All in a year) and the percentage of open CAPs (Open CAPS/Misoperations in a year). These metrics are meant only as potential examples for measuring performance. By requiring certain levels of performance or continuous improvement in these metrics, then the goal of the standard can be met without the administrative burden of tracking relatively unimportant dates such as when a cause was identified or when a CAP was developed</p>

Organization	Question 5 Comment
	<p>and the storage of large volumes of evidence records.</p> <p>Response: One of the objectives of this project is to bring consistency to metrics through the Section 1600 data request. In conjunction with data reporting, the proposed definition of Misoperation will improve identifying the appropriate category of Misoperation. The drafting team agrees that a results-based approach using metrics could simplify the standard and reduce compliance burdens; however, it may take several years of data collection to develop consistent and meaningful metrics for measure performance. No change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
Colorado Springs Utilities	<p>As noted in the response regarding R1. We believe that the specific terms need to be clarified in R3 as well to clarify the intended scope of covered situations.</p>
<p>Response: The drafting team thanks you for your comments. The occurrences of “BES Protection System” have been revised to pertain to “Protection Systems for BES Elements.” The use of “BES interrupting device” has been clarified in the standard’s Application Guidelines. Change made.</p>	
Manitoba Hydro	<p>Background - The words 'by requiring applicable entities to' would make sense after the words "The proposed requirements of the revised Reliability Standard PRC-004-3 meets the following objectives". Moreover, the terms Special Protection Systems, Remedial Action Schemes and Under-Voltage Load Shedding are used at the end of the Background section when these terms have already had acronyms attached to them above.</p> <p>Response: The suggested change does not provide any additional clarity. No change made.</p> <p>R2 - the words 'If a cause is identified' after the words 'cause(s) of each Misoperation' would be helpful. The way It reads, R2 is only applicable if a cause is identified and R3 is applicable if a cause if not identified so the Measures for each should be drafted in a</p>

Organization	Question 5 Comment
	<p>way that makes that point clear.</p> <p>Response: This has been clarified by the new Requirement R1 (and R3) that requires the identification of Misoperation which is typically when the entity will determine the cause. If a cause is not identified, further investigative actions must be taken (see new Requirement R4) until a cause is determined or a declaration of no cause is made. The concept of an action plan has been eliminated from the standard. Change made.</p> <p>R3 - the words ‘caused by a Protection System operation’ should be added after BES interrupting device operation to make the wording consistent with the other requirements.</p> <p>Response: The phrase “caused by a Protection System operation “ is only used in Requirement R1 when determining if a Protection System Misoperation has occurred. Once a Protection System Misoperation has been identified, an associated Protection System does not need to be restated in the requirements. The concept of an action plan (previously R3) has been eliminated from the standard. Change made.</p> <p>R4 - In reading the rationale for R4, it states that if a cause of a Misoperation is determined when implementing the action plan, you go back to R2 and develop a CAP. This isn’t evident on the face on the wording of the standard and the Rationale will be deleted going forward. R4/M4 - should be consistent with use of ‘and’ or ‘or’ when referring to the CAP and action plan, perhaps best option is to use ‘and/or’.</p> <p>Response: The rationale boxes will be moved to the Application Guidelines portion of the standard upon industry approval and remains with the standard. No change made.</p> <p>The concept of an action plan has been eliminated from the standard. Change made.</p> <p>Compliance - 1.1 - Manitoba Hydro has never before seen a reference to the definition of CEA per the NERC Rules of Procedure in this section, it seems unnecessary.</p> <p>Response: This is standardized text established by NERC for a Reliability Standard. No change made.</p> <p>Compliance - the phrase BES Protection System is elsewhere referred to as Protection</p>

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	<p>System for Facilities that are part of the BES which seems more accurate and should be consistently used.</p> <p>Response: The drafting team revised all the associated documents to reflect “Protection Systems for BES Elements.” Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
<p>Oncor Electric Delivery Company LLC</p>	<p>By using the definition of a Corrective Action Plan (CAP) in the NERC Glossary of terms, it is unclear what differences exist between a CAP and an “action plan” as written in PRC-004-3. Both appear to be the same until the Rationale for R3 states “implementing an action plan of additional investigation/monitoring may determine cause and lead to the development of a CAP in accordance to Requirement R2.” Oncor recommends that additional language be added that describes the intent and difference between a CAP and an “action plan”.</p> <p>Response: The concept of an action plan has been eliminated from the standard. Change made.</p> <p>Oncor would also like clarification as to what authority the CEA holds in determining the effectiveness of the corrective actions detailed in the CAP and/or “action plan”.</p> <p>Response: The CEA may determine if there is sufficient evidence that the entity has implemented their CAPs according to the criteria in each requirement. No change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
<p>City of Tacoma, Tacoma Public Utilities</p>	<p>Comments: Is it the intention of the PSM SDT that this version of the standard would require that all BES interrupting device operations be logged (documented) with a determination of whether the operation was caused by a Protection System? While it appears to be the intent of the draft revised standard that all interrupting device operations be reviewed at some level to determine if a Protection System caused the</p>

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	<p>operation, it is unclear whether explicit documentation of each interrupting device operation must be generated and retained for purposes of compliance with PRC-004-3.</p>
	<p>Response: The drafting team thanks you for your comment and intends that logging of the review occurs for those BES interrupting device operations caused by a Protection System operation or by manual intervention in response to a Protection System operation failure that meet the criteria in R1. The BES interrupting device owner would have evidence of its equipment operations and whether it was a Misoperation or not. The notified Protection System owner will use its notification to establish evidence of an operation. Routine switching operations are not intended to be logged and retained as evidence of compliance with this standard. No change made.</p>
<p>Florida Municipal Power Agency</p>	<p>First, R4 uses the phrase “as needed.” In doing research for legal precedence interpreting the phrase “as needed,” both in terms of contract interpretation and statutory construction, numerous cases throughout the country make it clear that, unless this phrase is clearly defined in the context in which it is used, this phrase is ambiguous and will only lead to conflict. For instance, the phrase indicates that (1) there is a level of discretion involved regarding an action that must be taken, and (2) someone must make a determination as to when such action is deemed “needed.” However, the standard is silent both as to what factors trigger the exercise of discretion and who makes the determination that a change to the CAP is “needed” - the entity or compliance staff. In this regard, FMPA recommends making it crystal clear what “as needed” means. For example, it could state “as needed to reflect any CAP revisions made by the responsible entity, as determined at the sole discretion of the responsible entity.”</p> <p>Response: The drafting team has revised Requirement R6 (previously R4) to removed “as needed” and added specificity that the CAP is updated when actions or the timetable changes. Change made.</p> <p>Second, R4 should recognize that not every investigation of a Misoperation ends in a CAP, e.g., those where no cause was found in accordance with R3.</p> <p>Response: This has been clarified by the new Requirement R1 (and R3) that requires the identification of Misoperation which is typically when the entity will determine the</p>

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	<p>cause. If a cause is not identified, further investigative actions must be taken (see new Requirement R4) until a cause is determined or a declaration of no cause is made. The concept of an action plan has been eliminated from the standard. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
<p>Midwest Reliability Organization NERC Standards Review Forum (NSRF)</p>	<p>For R2, depending on time of year, budget cycle, scope of work, 60 days is not sufficient to obtain funding for CAPs for some entities.</p> <p>Response: The 60-day period is to develop the CAP and not necessarily to obtain funding. Part of the CAP itself can be time to obtain the funding necessary to complete the CAP. No change made.</p> <p>Also, the first bullet under R2 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.</p> <p>Response: It is the responsibility of the Protection System owner to determine how wide spread the situation is and include the appropriate actions in its CAP. An evaluation of the CAP’s applicability to the entity’s other Protection Systems including other locations is intended to encourage diligence to prevent future Misoperations of the same cause and having an adverse effect on reliability. No change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
<p>Independent Electricity System Operator</p>	<p>Generally speaking, the standard is difficult to read, focusing on how instead of what. The drafting team should strengthen the description of the outcomes, and try to reduce the reliance on the application guideline and the rationales. (One has to read the rationales before understanding the meaning of the requirements.)</p>
<p>Response: The drafting team thanks you for your comment. Standards must focus on “what” is the required performance and not the</p>	

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	<p>“how” to achieve the required performance. The standard may appear written as the “how,” because requirements are based on the natural progression of the required performance. Several changes were made to the Requirements to improve clarity. Change made.</p>
<p>Flathead Electric Cooperative, Inc.</p>	<p>Generally, the standard does not seem to address the report of no events now being required by the RE, especially for entities that have only a few devices, the reporting burden for non-events should be clearly eliminated. It is not clear that it is eliminated. Only the reporting of actual misoperations should be required as defined.</p>
<p>Response: The drafting team thanks you for your comment. The reporting requirement has been removed from the standard. Change made.</p>	
<p>American Electric Power</p>	<p>In the Rationale for R2 box, a reference is made to R4. This appears to be a typo and should be changed to R3.</p> <p>Response: The requirements have been restructured causing the rationale boxes to change. Change made.</p> <p>Since an evaluation is not part of the Corrective Action Plan definition, please make the following modification to the first bullet of R2: " Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and also an evaluation of the Action Items applicability to the entity’s Protection Systems at other locations, or.."</p> <p>Response: The drafting team agrees an “evaluation” is separate from the CAP and has modified the proposed Requirement R5 (previously R2). Change made.</p> <p>AEP recommends revising R2, R3, and R4 to specify that only the owner(s) of the Protection System component(s) that misoperated are responsible for applicable requirements.</p> <p>Response: Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners’ responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. According to the standard, each entity has an independent responsibility to identify a Misoperation of its Protection System components, if any,</p>

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	<p>beginning with the BES interrupting device owner through any notified Protection System owner. Change made.</p> <p>Measure 2 should be revised to remove the statement “explaining why there is no need to develop a CAP.” This is consistent with Measure 3.</p> <p>Response: Measure M2 was revised and is now M5. Change made.</p> <p>Declaration is described elsewhere in the standard. The Standard may read more clearly if the existing R2 and R3 were switched such that the requirement to develop a CAP (R2) came <i>after</i> the requirement to identify a cause or develop an action plan (R3) to complete further investigation.</p> <p>Response: The Requirements were rewritten to clarify the two instances where a declaration can be used, one to end the entity’s investigation for a the cause of a Misoperation and the other to state why corrective actions (i.e., CAP) are beyond the entity’s control or would not improve BES reliability and that no further corrective actions will be taken. No change made.</p> <p>The phrase "composite Protection System", which is described in the Application Guidelines section, is not used in the Requirements, Measures, or Compliance sections. AEP requests "Protection System" to be replaced with "composite Protection System" where appropriate throughout the standard.</p> <p>Response: The drafting team is proposing a definition for the term “Composite Protection System.” Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
<p>Ingleside Cogeneration LP</p>	<p>Ingleside Cogeneration shares the project team’s desire to retain a scholarly and cooperative approach to the assessment of Misoperations. However, we believe that the regulatory pressure will mount - particularly as NERC’s events analysis numbers continue to show Misoperations as a primary component in nearly every wide area outage. This means concepts that are implicitly understood today will be immaterial in</p>

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	<p>the future. For example, it is easy to see that a CEA may assess a violation for a single missing relay operation evaluation out of hundreds that may have occurred during a wide-area weather event. Despite assurances that the CEA will take the circumstances “under consideration”, we are not convinced that that will always be the case.</p> <p>Response: Use of percentages is practical for assessing violations for fixed quantities; however, Protection System operations are variable and event driven. The drafting team constructed the VSL according to the NERC Violation Severity Level Guidelines. No change made.</p> <p>If the drafting team is reluctant to modify the definition of “Misoperation” or PRC-004-3’s requirements, there may be an opportunity to capture these understandings in a binding way in the RSAW. There is a new program that has been initiated by NERC to include Compliance representatives in the standards drafting process for situations just like these. If we are able to provide commentary on the auditors’ instructions captured in the RSAW, it would alleviate our doubts that understandings reached during the development phase would be retained when the standard becomes mandatory.</p> <p>Response: The drafting team anticipates posting a draft PRC-004-3 RSAW so that entities will have an opportunity to consider auditing approaches. Posting is expected mid-way through the draft 4 posting of PRC-004-3. No change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
<p>Xcel Energy</p>	<p>It is important to be able to see the draft RSAW, as it relates to what kind of evidence, if any, would be required to demonstrate accurate assessment of a slow trip. This could be particularly problematic, as not all have DME installed to be able to capture data to be able to measure both the start and stop of the operation.</p>
<p>Response: The drafting team thanks you for your comments. The drafting team anticipates posting a draft PRC-004-3 RSAW so that entities will have an opportunity to consider auditing approaches. Posting is expected mid-way through the draft 4 posting of PRC-004-3. No change made.</p>	

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	<p>The slow trip category is included because it is a type of Misoperation which should be identified when possible. In cases where the entity does not have access to Disturbance Monitoring Equipment (DME), a slow trip may be revealed by BES instability and tripping of more than then minimum Element(s). The proposed standard does not require the installation of DME which is being addressed by Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018). The proposed standard does not require an entity to have certain personnel and only specifies the performance required for Misoperation identification and correction. Entities with Protection Systems that are applicable to the standard are required to identify any Misoperation, determine its cause(s), and correct the cause(s) to prevent future occurrences. No change made.</p>
<p>Los Angeles Department of Water and Power</p>	<p>LADWP recommends that the Drafting Team give due weight to the Internal Controls Process (ICP). We believe the responsible entity should be allowed the latitude to determine the Corrective Action Plan (CAP) that follows the ICP approach.</p> <p>Response: The drafting team continues to support the proposed standard as currently structured. The draft requirements allow Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities. However, internal controls are only a mechanism to help auditors determine the depth and breadth of testing as it pertains to compliance with the related Reliability Standard and specific requirements and when necessary understand the facts and circumstances of instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process. No change made.</p> <p>LADWP also recommends that the standard include specifications that the entity identify mitigating factors performed under the CAP that specifically address the misoperation.</p> <p>Response: The NERC Glossary definition of Corrective Action Plan includes the phrase “remedy a specific problem”. In the context of this standard, the “problem” is the cause a Misoperation. Mitigating actions may be included as a part of the CAP. No change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	

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<p>Kansas City Power & Light</p>	<p>R2 requires a CAP except in cases where the entity can "Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability" R2 does not recognize that every CAP requires resources to complete and that the industry has limited resources. There are cases where the required resources to complete a CAP at multiple locations provides minimal increase in reliability. If these low productivity CAPs are required to be completed the net result is a decrease in BES reliability since other more productive work will not be done due to lack of resources.</p> <p>Response: Prompt identification of a Misoperation is important regardless of its perceived significance. Identifying a Misoperation and its cause(s) leads to preventing reoccurrence which, without correction, could lead to a reduction in reliability. Additionally, the identification of a Misoperation cause leads the entity to considering its other Protection Systems including other locations which may result in identifying and correcting a potential problem with another Protection System which may be significant to reliability. The standard provides options for entities to explain why actions were not taken. No change made.</p> <p>The entity should be able to state the CAP was completed at only the affected site and was not rolled out system wide due to poor ratio of resources required to reliability benefit gained.</p> <p>Response: An entity may elect not to address/correct the causes of Protection System Misoperations at other locations as there is no required performance at this time; however, the drafting team believes responsible entities will create a program to address other locations that is commensurate with its resources and impact to reliability. No change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
<p>Bonneville Power Administration</p>	<p>R2 requires each TO, GO, or DP to develop a corrective action plan, but it does not indicate which TO, GO, or DP must do this. Is this intended to be the TO, GO, or DP that owns the interrupting device or the TO, GO, or DP that owns the protection system?</p>

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	<p>BPA recommends the following wording for the beginning of R2: Each TO, GO, or DP that owns a component of a protection system identified as contributing to a misoperation, as determined per R1, shall within 60 calendar days of identifying the cause of each misoperation: (insert bullet points for R2).</p> <p>Similar to the comment above for R2, BPA believes that R3 does not make it clear which TO, GO, or DP the requirement applies to. BPA recommends that the entity identified by R1 as required to initiate the investigation of an interrupting device operation (BPA believes this should be the owner of the protective relays) should be the entity required to complete the actions in R3.</p> <p>BPA believes that similar to R2 and R3, R4 should be more specific about which TO, GO, or DP the requirement applies to.</p> <p>Response: Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.</p> <p>The last paragraph of the Background section states that where PRC-004-WECC-1 overlaps with this continent-wide standard, entities are expected to comply with the more stringent standard. In our comments to the previous draft, BPA suggested that the Background section simply state which of the standards takes precedence instead of leaving it to the entities to determine which standard is more stringent.</p> <p>The response to this comment was that entities are required to comply with both the continent-wide standard and any applicable regional standards. This response seems to contradict the Background statement. BPA requests clarification on whether entities are expected to comply with both standards or only the more stringent standard, and</p>

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	<p>how an entity should determine which standard is more stringent as the standards cover very different issues. BPA believes that if an entity is expected to comply with both standards, that should be stated, or perhaps this part of the Background statement should be removed.</p> <p>Response: An entity in the Western Interconnection will be responsible for meeting the PRC-004-3 requirements and those in the regional standard PRC-004-WECC-1. The drafting team identified potential concerns between the standards and is proposing 12 additional calendar months for implementation of PRC-004-3. This is additional time to allow the Western Interconnection to revise its regional standard to correct an identified compliance overlap and any potential gaps in reliability. The drafting team removed the regional references to avoid confusion. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
<p>Wisconsin Electric Power Company</p>	<p>Since owners of BES Protection Systems will be required by this standard to review all operations, it would be helpful to define the term "Protection System operation", at least as it is used in this standard.</p>
<p>Response: The drafting team thanks you for your comments and contends that the phrase "Protection System operation" is a common industry phrase and does not need a definition. No change made.</p>	
<p>Southern Company - Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Mississippi Power Company; Gulf Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing</p>	<p>Southern Company supports the SERC comments and are including the following additional comments:</p> <ol style="list-style-type: none"> 1. By using the definition of a Corrective Action Plan (CAP) in the NERC Glossary of terms as well as the term 'action plan' in R3, it is unclear what differences exist between a CAP and an "action plan" as written in PRC-004-3. Please modify language to be consistent or add language that describes the intent and difference between a CAP and an "action plan". <p>Response: The concept of an action plan has been eliminated from the standard.</p>

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	<p>Change made.</p> <p>2. R2 and R3 should be restructured such that it is immediately apparent that R2 deals with Misoperations with an identified cause and R3 deals with Misoperations without an identified cause. This could be accomplished by phasing that condition first in the requirement so that the required actions that are bulleted immediately follow the "shall" such as:</p> <p>"R2: For each Misoperation with an identified cause, the entity shall either develop a CAP ... or declare why ..." and</p> <p>"R3: For each Misoperation without an identified cause, the entity shall either develop an action plan ... or declare why ..."</p> <p>Response: The concept of an action plan has been eliminated from the standard; however, the proposed Requirement R4 requires the entity to perform investigative action when circumstances require additional study or time to determine the cause(s) of a Misoperation. Requirement R5 and R6 respectively address CAP development and implementation by the Protection System component owner to correct the cause(s) of a Misoperation. Change made.</p> <p>3. R4 should be re-structured to flow more smoothly, as follows; "R4. Each entity shall implement and revise, as needed, each CAP or action plan.</p> <p>Response: Requirements R5 and R6 (previously R2 and R4) now clearly delineate CAP development and implementation. Change made.</p> <p>4. The three bullets found at the top of page 6 of draft 3 of the standard should be the three requirements of this standard. Has any consideration of making those three items the actual requirements?</p> <p>Response: The standard's Requirements meet the intended objectives of the three bullets. No change made.</p> <p>5. Please consider using the phrase "component that misoperated" rather than</p>

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	<p>"component that contributed to the misoperation" in the standard for clarity.</p> <p>Response: This clause was in the rationale box of the previous draft 3; however, Requirement R1 has been revised for clarification and does not use the phrasing "contributed to." Change made.</p> <p>6. There is too much unnecessary date bookkeeping in the Requirements. We recommend deleting all existing date clocks linked to each event and specify a resolution time limit for investigative action plans/CAPs to be the filing date deadline for each quarter. The establishment of multiple time frames for each detail of a Protection System operation will not improve reliability. The establishment of investigative action plans and/or completion of necessary Corrective Action Plans in a timely fashion are the actions which will affect the reliability of the Protection System.</p> <p>Response: One of the objectives of this project is to bring consistency to metrics through the Section 1600 data request. In conjunction with data reporting, the proposed definition of Misoperation will improve identifying the appropriate category of Misoperation. The drafting team agrees that a results-based approach using metrics could simplify the standard and reduce compliance burdens; however, it may take several years of data collection to develop consistent and meaningful metrics for measure performance. No change made.</p> <p>Response: The associated dates and timetables allow the Requirements to be measurable. No change made.</p> <p>7. In reference to the above comment, if the timeframe are to remain, the SDT is strongly encouraged to move toward an internal controls format for this standard.</p> <p>Response: The drafting team continues to support the proposed standard as currently structured. The draft requirements allow Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities. However, internal controls are only a mechanism to help auditors determine the depth and breadth of testing as it pertains to compliance with the related Reliability Standard and specific requirements and when necessary understand the facts and circumstances of</p>

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	instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process. No change made.
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
Entergy Services, Inc. (Transmission)	Suggest “Composite Protection System” as listed in the Guidelines and Technical Basis section (page 14 of 24) be a defined term for this standard.
<p>Response: The drafting team thanks you for your suggestion. The drafting team is proposing a definition for the term “Composite Protection System.” Change made.</p>	
Northeast Power Coordinating Council	<p>The Compliance Section of Standard has “The Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System shall retain evidence for all Misoperations with an open investigation, action plan, or CAP even if the BES interrupting device operation occurred prior to the current audit period.” The word “open” should precede not only investigation, but action plan and CAP for clarity. It should be made to read “open investigation, open action plan, or open CAP even if the BES interrupting device operation occurred prior to the current audit period”.</p> <p>Response: The evidence retention section has been revised to require evidence to be retained a defined period after the completion. This would include any “open” CAPs and other ongoing performance of the standard. Change made.</p> <p>What is an Entity’s compliance obligation for an open investigation or open action plan that occurred prior to regulatory approval of this Standard but in the current audit period of an entity?</p> <p>Response: The entity must be compliant with the standard that was enforceable at the time through the transition (implementation) of the new standard. No change made.</p> <p>The new standard establishes specific time limits. If an entity has an operation to investigate the day prior to the compliance obligation date, does the 120 day time limit</p>

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	<p>apply the day the Standard is obligatory?</p> <p>Response: No. The new standard will only apply from the effective date forward. No change made.</p> <p>Regarding the Implementation Plan for Requirements R1, R2, R3 and R4:</p> <p>“Entities shall be 100% compliant for any new Protection System Operation on the first day of the first calendar quarter twelve months” (this is the compliance obligation date) “following applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twelve months following Board of Trustees adoption. Protection System operations that occur before the compliance date shall comply with the previous version of the Standard.”</p> <p>In this section of the Implementation Plan, what is meant by “new”? Is “new” any operation that occur after the compliance obligation date, or during the window of implementation between regulatory approval and compliance obligation date?</p> <p>Response: The reference to “new” has been removed. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
<p>ExxonMobil Research and Engineering</p>	<p>The documentation requirements for maintaining a database of every operation of a BES interrupting device, which are laid out in Measure M1, represent a significant step change in documentation requirements when compared with the current misoperation analysis and reporting requirements. Unintentional mismanagement of a database that identifies every operation by time, date, and date of review during a six year audit window poses no significant risk to the reliable operation of the Bulk Electric System. However, enforcement of this measure will likely identify clerical or other unintentional errors made during the process of tracking misoperations that will impede NERC’s ability to address violations that pose a moderate or severe threat to the reliability of the Bulk Electric System.</p> <p>The underlying objective of the data compiled in the measure appears to be a ‘best</p>

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	<p>practice’ method for retaining data necessary to meet the quarterly reporting requirements for misoperation reporting; specifically reporting of the ‘total number of operations’. While it is understood, that NERC is utilizing this quarterly reporting data to develop metrics to track the performance of BES Protective Systems, the required implementation of a prescriptive tracking method in a Reliability Standard does not balance the need and method for addressing the need, and compliance with the quarterly reporting of misoperation data is already driven by NERC’s Rules of Procedure.</p> <p>The SDT should consider modifying Measure M1 in such a way that it requires misoperation analysis reports (Corrective Action Plans and Action Plans) to include the level of detail addressed in Measurement M1 (time & date of operation, date analysis determined it was a misoperation, etc.). This modification would address the need to ensure that misoperations are appropriately analyzed within a reasonable amount of time while avoiding the implementation of a Reliability Standard requirement that could create enforcement actions that hinder NERC’s ability to address potential violations that pose a moderate or serious threat to the Bulk Electric System.</p>
<p>Response: The drafting team thanks you for your comments and notes that Measures are not enforceable. Measures provide examples of evidence that may be used to demonstrate compliance with the requirements. The drafting team removed all of the reporting requirements from the proposed standard. The data will be collected through the NERC Rules of Procedure, Section 1600, Request for Information or Data process. Metrics will be developed by NERC for reliability assessments, for example. The requirements and associated time frames ensure that the responsible entities are diligent about Misoperation identification, CAP development and completion. No change made.</p>	
<p>PPL NERC Registered Entities</p>	<p>The PPL NERC Registered Entities (PPL Electric Utilities, PPL Generation LLC, PPL Energy Plus, LG&E and KU Services) are in agreement with the spirit of the North America Generator Forum Standards Review Team comments for the successive ballot for Project 2010-05.1 Protection Systems: Misoperations.</p> <p>We recommend deleting all date clocks linked to each event and replace them with a final resolution time limit for action plans/CAPs and/or replace them with a filing date</p>

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	<p>deadline to identify, review, and disposition of each operation for each event. The establishment of multiple time frames for each detail of a Protection System operation will not improve reliability; the completion of any necessary Corrective Action Plans are the actions which will affect the reliability of the Protection System operations.</p> <p>Response: The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation identification, CAP development and completion. Having time periods accounts for seasonal workloads and unforeseen issues with implementing a CAP. The timetables make the requirements auditable. No change made.</p> <p>In various locations of the draft, Protection System misoperations are discounted as misoperations for situations where other redundant protection may have adequately operated. In these instances, perhaps the classification should be changed to non-reportable misoperation rather than simply that they are not Misoperations.</p> <p>Response: The composite Protection System is the collective operation of the entire Protection System for an Element which is included in determining whether a Misoperation occurred. To clarify the usage of the terminology, the drafting team is proposing the definition “Composite Protection System” which has an exclusion for backup protection provided by a remote Protection System. Change made.</p> <p>The three bullets found at the top of page 6 of draft 3 of the standard are possibly sufficient requirements for this standard. Has any consideration been given to making those three items the actual requirements?</p> <p>Response: The standard’s Requirements meet the intended objectives of the three bullets. No change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
<p>Liberty Electric Power LLC</p>	<p>The standard would be simplified by combining R1 through R4 to state:</p> <p>R1 For each activation of a BES interrupting device initiated by a Protection System, the</p>

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	<p>entity shall identify the cause of the operation.</p> <p>R1.1 If the activation is determined to be a misoperation, the entity shall develop a corrective action plan, or explain in a declaration why a CAP cannot reasonably be instituted.</p> <p>R1.2 If no cause can be determined, the entity shall develop an action plan for further investigation, or explain in a declaration why no further action is warranted.</p> <p>R1.3 All action plans shall be developed within 180 days of the operation, or notification of an operation of a BES interrupting device caused by the RE's Protection System.</p> <p>R2 All action plans developed under R1 shall be implemented or revised as needed until complete.</p> <p>Response: The standard has been revised to provide one activity for a single reliability goal in accordance with standard drafting guidelines. The drafting team restructured the previous requirements into separate requirements. Change made.</p> <p>The additional detail in the current version (work timetables, other facilities) should be moved to the measures, as they are the output of the requirements.</p> <p>Response: Examples of CAPs are provided in the Application Guidelines. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
<p>Essential Power, LLC</p>	<p>There is too much bookkeeping required in the Requirements. We recommend deleting all date clocks linked to each event and replace them with a final resolution time limit for action plans/CAPs and/or replace them with a filing date deadline to identify, review, and disposition of each operation for each event. The establishment of multiple time frames for each detail of a Protection System operation will not improve reliability; the completion of any necessary Corrective Action Plans are the actions which will affect the reliability of the Protection System operations.</p> <p>Response: One of the objectives of this project is to bring consistency to metrics</p>

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	<p>through the Section 1600 data request. In conjunction with data reporting, the proposed definition of Misoperation will improve identifying the appropriate category of Misoperation. The drafting team agrees that a results-based approach using metrics could simplify the standard and reduce compliance burdens; however, it may take several years of data collection to develop consistent and meaningful metrics for measure performance. No change made.</p> <p>Response: The associated dates and timetables allow the Requirements to be measurable. No change made.</p> <p>In various locations of the draft, Protection System misoperations are discounted as misoperations for situations where other redundant protection may have adequately operated. In these instances, perhaps the classification should be changed to non-reportable misoperation rather than simply that they are not Misoperations.</p> <p>Response: The composite Protection System is the collective operation of the entire Protection System for an Element which is included in determining whether a Misoperation occurred. To clarify the usage of the terminology, the drafting team is proposing the definition “Composite Protection System” which has an exclusion for backup protection provided by a remote Protection System. Change made.</p> <p>The three bullets found at the top of page 6 of draft 3 of the standard should be the three requirements of this standard. Has any consideration been given to making those three items the actual requirements?</p> <p>Response: The standard’s Requirements meet the intended objectives of the three bullets. No change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
<p>Cogentrix Energy Power Management, LLC</p>	<p>There is too much bookkeeping required in the Requirements. We recommend deleting all date clocks linked to each event and replace them with a final resolution time limit for action plans/CAPs and/or replace them with a filing date deadline to identify, review, and disposition of each operation for each event. The establishment of</p>

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	<p>multiple time frames for each detail of a Protection System operation will not improve reliability; the completion of any necessary Corrective Action Plans are the actions which will affect the reliability of the Protection System operations.</p> <p>Response: One of the objectives of this project is to bring consistency to metrics through the Section 1600 data request. In conjunction with data reporting, the proposed definition of Misoperation will improve identifying the appropriate category of Misoperation. The drafting team agrees that a results-based approach using metrics could simplify the standard and reduce compliance burdens; however, it may take several years of data collection to develop consistent and meaningful metrics for measure performance. No change made.</p> <p>The associated dates and timetables allow the Requirements to be measurable. No change made.</p> <p>In various locations of the draft, Protection System misoperations are discounted as misoperations for situations where other redundant protection may have adequately operated. In these instances, perhaps the classification should be changed to non-reportable misoperation rather than simply that they are not Misoperations.</p> <p>Response: The composite Protection System is the collective operation of the entire Protection System for an Element which is included in determining whether a Misoperation occurred. To clarify the usage of the terminology, the drafting team is proposing the definition “Composite Protection System” which has an exclusion for backup protection provided by a remote Protection System. Change made.</p> <p>The three bullets found at the top of page 6 of draft 3 of the standard should be the three requirements of this standard. Has any consideration been given to making those three items the actual requirements?</p> <p>Response: The standard’s Requirements meet the intended objectives of the three bullets. No change made.</p>
	<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>

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Pepco Holdings Inc & Affiliates	<p>To avoid confusion, Requirements R2, R3, and R4 should be re-worded to make it clear that they apply only to those entities whose Protective System misoperated and not to the interrupting device owner. The following language is suggested:</p> <p>R2. “Each Transmission Owner, Generation Owner, or Distribution Provider, whose Protection System misoperated, shall within 60 calendar days of identifying the cause of each Misoperation...”</p> <p>R3. “Each Transmission Owner, Generation Owner, or Distribution Provider shall, within 180 calendar days of the interruption of the BES Facility due to a Protective System Misoperation, complete for each Misoperation without an identified cause....”</p> <p>R4. “Each Transmission Owner, Generation Owner, or Distribution Provider, whose Protection System misoperated, shall implement each CAP or action plan, and revise as needed through completion.”</p>
<p>Response: The drafting team thanks you for your comments. Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners’ responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.</p>	
Texas Reliability Entity	<p>We are concerned that the applicability of the Standard limits the misoperation analysis only to BES Element Protection Systems. Under the new BES definition and guidance documents, there will be numerous examples of misoperations on non-BES Element Protection Systems which could have a major impact on the BES when the fault must be cleared by remote backup relays.</p> <p>Example: Consider a 50MVA generator connected to a substation via a radial line. Under the new BES guidance, the generator is part of the BES while the interconnecting radial line would not be part of the BES under exclusion E1(b). If a fault occurs on the non-BES radial line and the Protection System fails to trip, the fault must then be</p>

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	<p>cleared by either local or remote backup relays at the interconnecting substation(s).</p> <p>Under this scenario with the current proposed PRC-004 requirements, the owner of the non-BES radial line has no obligation to analyze or correct the Misoperation. The PRC-027 SDT received comments with similar concerns in its last revision. They have drafted language to ensure that coordination of non-BES Protection Systems between different Functional Entities. The PRC-004 SDT may want to consider similar language to ensure that all Misoperations which can affect the reliable operation of the BES are analyzed and corrected.</p>
<p>Response: The drafting team thanks you for your comment. The standard addresses the Misoperation of Protection Systems for BES Elements. If the Composite Protection System operated correctly in backing up the failure of a non-BES Element, the operation would be considered correct. If the Composite Protection System failed to operate correctly for the non-BES Element fault, that would be considered a Misoperation. No change made.</p>	
JEA	<p>We believe that the issues should be handled through modification of PRC003 not PRC004.</p>
<p>Response: The drafting team thanks you for your comment. In FERC Order No. 693, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004; therefore, PRC-003-1 will be retired. No change made.</p>	
seattle city light	<p>We would like to reiterate our previous comments that this Drafting Team give due weight to the Internal Controls Process (ICP). We believe the responsible entity should be allowed the latitude to determine the Corrective Action Plan (CAP) that follows the ICP approach.</p> <p>Response: The drafting team continues to support the proposed standard as currently structured. The draft requirements allow Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities. However, internal controls are only a mechanism to help auditors determine the depth and</p>

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	<p>breadth of testing as it pertains to compliance with the related Reliability Standard and specific requirements and when necessary understand the facts and circumstances of instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process. No change made.</p> <p>We would also suggest that the ICP include specifications that the entity identify mitigating factors performed under the CAP that specifically address the Misoperation.</p> <p>Response: The NERC Glossary definition of Corrective Action Plan includes the phrase “remedy a specific problem”. In the context of this standard, the “problem” is the cause a Misoperation. Mitigating actions may be included as a part of the CAP. No change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
<p>Sacramento Municipal Utility District</p>	<p>We would like to reiterate our previous comments that this Drafting Team give due weight to the Internal Controls Process (ICP). We believe the responsible entity should be allowed the latitude to determine the Corrective Action Plan (CAP) that follows the ICP approach.</p> <p>Response: The drafting team continues to support the proposed standard as currently structured. The draft requirements allow Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities. However, internal controls are only a mechanism to help auditors determine the depth and breadth of testing as it pertains to compliance with the related Reliability Standard and specific requirements and when necessary understand the facts and circumstances of instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process. No change made.</p> <p>We would also suggest that the standard include specifications that the entity identify mitigating factors performed under the CAP that specifically address the misoperation.</p>

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	<p>Response: The NERC Glossary definition of Corrective Action Plan includes the phrase “remedy a specific problem”. In the context of this standard, the “problem” is the cause a Misoperation. Mitigating actions may be included as a part of the CAP. No change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
<p>Public Utility District No. 1 of Snohomish County</p>	<p>We would like to reiterate our previous comments that this Drafting Team give due weight to the Internal Controls Process (ICP). We believe the responsible entity should be allowed the latitude to determine the Corrective Action Plan (CAP) that follows the ICP approach.</p> <p>Response: The drafting team continues to support the proposed standard as currently structured. The draft requirements allow Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities. However, internal controls are only a mechanism to help auditors determine the depth and breadth of testing as it pertains to compliance with the related Reliability Standard and specific requirements and when necessary understand the facts and circumstances of instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process. No change made.</p> <p>We would also suggest that the standard include specifications that the entity identify mitigating factors performed under the CAP that specifically address the misoperation.</p> <p>Response: The NERC Glossary definition of Corrective Action Plan includes the phrase “remedy a specific problem”. In the context of this standard, the “problem” is the cause a Misoperation. Mitigating actions may be included as a part of the CAP. No change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
<p>Southwest Power Pool Reliability Standards</p>	<p>We would like to see a RSAW for this particular standard to better understand what</p>

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Development Team	<p>level of review and or evidence, if any, auditors will require to determine that you assessed your operations adequately for R1.</p> <p>Response: The drafting team anticipates posting a draft PRC-004-3 RSAW so that entities will have an opportunity to consider auditing approaches. Posting is expected mid-way through the draft 4 posting of PRC-004-3. No change made.</p> <p>For instance if you didn't have certain monitoring equipment that captures data for protection system elements, then the data available would be limited for assessing slow trips.</p> <p>Response: The slow trip category is included because it is a type of Misoperation which should be identified when possible. In cases where the entity does not have access to Disturbance Monitoring Equipment (DME), a slow trip may be revealed by BES instability and tripping of more than then minimum Element(s). The proposed standard does not require the installation of DME which is being addressed by Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018). No change made.</p> <p>Depending upon the guidance requested in the SPP comments (what will be required to prove that all faults have been analyzed) the time frames may become difficult to maintain especially during storm seasons.</p> <p>Response: The <i>Sanction Guidelines of the North American Electric Reliability Corporation</i>, 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, including specific language in the proposed standard complicates a low frequency event where a compliance violation might occur. No change made.</p> <p>Likewise, the 60 days required to develop a corrective action once the cause is determined could become difficult for severe or extreme events. In extreme cases dynamic power flow models may need to be developed and applied to system studies</p>

Organization	Question 5 Comment
	<p>before the CAP can be developed.</p> <p>Response: The CAP by definition is a set of actions and a timetable to remedy a specific problem (i.e., Misoperation cause). In this case, the entity would include performing dynamic power flow simulations as an action within the CAP. Similarly, the timetable would account for the time needed to perform the simulation. No change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
<p>Indiana Municipal Power Agency</p>	<p>Indiana Municipal Power Agency agrees with the comments submitted by Florida Municipal Power Agency and has a couple of additional comments. Since the comment document is not formatted for this purpose, we will submit them here.</p> <p>The standard is titled Protection System Misoperation Identification and Correction, not Operation Identification and Submittal. IMPA does see that an organization might keep track of operations but to require this action by a standard requirement and then potentially find an entity in non-compliance is over reaching for this Protection System Misoperation standard. In order to be in compliant with this stadnard, an entity should only be required to perform the action of Protection System Misoperation Identification and Correction which is the standard title.</p> <p>Response: Each entity must review its Protection System operations according to Requirement R1 (including R3) in order to identify potential Misoperations. Without that requirement, there is no measure whether or not the entity reviewed the necessary operations. No change made.</p> <p>Another problematic area involves the "same 120 day period of a BES interrupting device operation caused by a Protection System operation". What happens if the owner of the Protection System component is notified toward the end of the 120 day period of a BES interrupting device operation (say 119 day) and there is not sufficient time for an investigation by the Protection System owner into the cause of the trip? The Protection System owner should not be found non-compliant for requirement 1.2 if not enough time is given to them to properly investigate the reason for the operation of</p>

Organization	Question 5 Comment
	<p>the Protection System.</p> <p>Response: Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.</p>
<p>Response: The drafting team thanks you for your comments; please see the above responses.</p>	
Western Electricity Coordinating Council	<p>WECC believes that an Internal Controls Process with Risk Based requirements should be implemented in this standard.</p>
<p>Response: The drafting team thanks you for your comments and continues to support the proposed standard as currently structured. The draft requirements allow Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities. However, internal controls are only a mechanism to help auditors determine the depth and breadth of testing as it pertains to compliance with the related Reliability Standard and specific requirements and when necessary understand the facts and circumstances of instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process. No change made.</p>	

END OF REPORT