Consideration of Comments

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

The Protection Systems: Phase 1 (Misoperations) Drafting Team thanks all commenters who submitted comments on the second draft of the PRC-004-3 standard for Protection System Misoperations. These standards were posted for a 45-day public comment period from July 25, 2012 through September 7, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 95 sets of comments, including comments from approximately 230 different people from approximately 145 companies representing 9 of the 10 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 Consideration of all Comments Received

Definition

The drafting team made several changes to the definition. The term 'composite Protection System' was incorporated into the introductory sentence of the definition to indicate that a Misoperation pertains to the 'composite Protection System' and clarify that only the overall performance of the Protection System is considered when determining a Misoperation. The definition categories were edited and revised to provide more specificity and clarity.

Applicability

The drafting team revised the Facilities portion of the Applicability section to provide more specificity. Facilities 'included' are stated in 4.2.1 and 4.2.2, and facilities excluded are stated in 4.2.3 and 4.2.4. The Applicability text box provides explanation for the exclusion of the facilities listed in 4.2.3 and 4.2.4.

Requirements

The drafting team revised Requirement R1 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.

The drafting team revised Requirement R4, removing the parts to eliminate the administrative aspects.

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

Measures

The drafting team modified the measures to complement the revised requirements.

Compliance

C 1.2 Evidence Retention – The following sentence was added for clarity: "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 boiler plate language was modified for clarity.

C 1.4 Additional Compliance Information – The language was removed. All reporting obligations have been removed from the standard.

VLSs

Complementary changes were made to the VSLs in conjunction with the revised requirements.

Guidelines and Technical Basis

Complementary changes were made to the Guidelines and Technical Basis corresponding to all changes to the standard. More supporting discussions, explanations, and examples for all aspects of the standard were provided.

Implementation Plan

The Effective Date was revised from six months to twelve months following applicable regulatory approvals. Other complementary changes were made to the Implementation Plan.

Unresolved Minority Views

- A few commenters expressed concern about the 120 day timeframe to review Protection System operations. The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. This 120 day time frame takes into account the seasonal nature of Protection System operations as well as outage constraints for investigative purposes. If the investigation doesn't reveal a cause within this timeframe, the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.

- A few commenters felt having formal notification to another entity of an operation was unnecessary. The drafting team disagreed and clarified Requirement R1 to show that the interrupting device owner will do the initial investigation and will contact other Protection System owners only if a correct operation cannot be determined. In this case, the investigative information is passed from the interrupting device owner to the other owners. If the investigation doesn't reveal a cause within this timeframe, the notified entity has the remainder of the 120-day period, and if needed can establish an action plan (per Requirement R3) with its own time table for further investigation to determine whether their component operated correctly.

- Several commenters asked the drafting team to combine all or parts of Requirements R1, R2 and R3 into one requirement with one timeframe. The drafting team believes an overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Guidelines and Technical Basis section of the standard has been revised to add clarity for the independent 120 and 60 day timeframes.

- A large percentage of the entities that commented stated that the 10-day intervals between severity levels for Requirements R1, R2, or R3 were too short. The drafting team used the NERC guideline: "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended." However, based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

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

10 — Regional Reliability Organizations, Regional Entities

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	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.	Ben Wu	Orange and Rockland Utilities	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1

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

11.	Michael Lombardi	Northeast Utilities	NPCC	1
12.	Bruce Metruck	New York Power Authority	NPCC	6
13.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
14.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
15.	Robert Pellegrini	The United Illuminating Company	NPCC	1
16.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
17.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
18.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
19.	Brian Robinson	Utility Services	NPCC	8
20.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2

				1	2	3	4	5	6	7	8	9	10
2.	Group	Steve Alexanderson	Western Small Entity Comment Group			X	X					X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dale Dunkel	Okanagan PUD	WECC	1
2.	Russell A. Noble	Cowlitz County PUD No. 1	WECC	3, 4, 5
3.	Steven J. Grega	Public Utility District #1 of Lewis County	WECC	5
4.	Steven Powell	Trans Bay Cable	WECC	1
5.	Eric Scott	City of Palo Alto	WECC	3
6.	Ronald Sporseen	Blachly-Lane Electric Cooperative	WECC	3
7.	Ronald Sporseen	Central Electric Cooperative	WECC	3
8.	Ronald Sporseen	Consumers Power	WECC	1, 3
9.	Ronald Sporseen	Clearwater Power Company	WECC	3
10.	Ronald Sporseen	Douglas Electric Cooperative	WECC	3
11.	Ronald Sporseen	Fall River Rural Electric Cooperative	WECC	3
12.	Ronald Sporseen	Northern Lights	WECC	3
13.	Ronald Sporseen	Lincoln Electric Cooperative	WECC	3
14.	Ronald Sporseen	Raft River Rural Electric Cooperative	WECC	3
15.	Ronald Sporseen	Lost River Electric Cooperative	WECC	3
16.	Ronald Sporseen	Salmon River Electric Cooperative	WECC	3
17.	Ronald Sporseen	Umatilla Electric Cooperative	WECC	1, 3

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

18.	Ronald Sporseen	Coos-Curry Electric Cooperative	WECC	3
19.	Ronald Sporseen	West Oregon Electric Cooperative	WECC	4
20.	Ronald Sporseen	Pacific Northwest Generating Cooperative	WECC	3, 4, 8
21.	Ronald Sporseen	Power Resources Cooperative	WECC	3, 5
22.	Ronald Sporseen	Lane Electric Cooperative	WECC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Brad Haralson	Associated Electric Cooperative Inc - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	David Thorne	Pepco Holdings Inc & Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Delmarva Power & Light Co	RFC	1, 3
2.	Alvin Depew	Pepco Holdings Inc	RFC	1, 3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	Jonathan Hayes	Souhwest 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 Pool	SPP	NA
3.	John Allen	City Utilities of Springfield	SPP	1, 4
4.	Bud Averill	Grand River Dam Authority	SPP	1, 3, 5
5.	Tim Bobb	Westar Energy	SPP	1, 3, 5, 6
6.	John Boshears	City Utilities of Springfield	SPP	1, 4
7.	Anthony Cassmeyer	Western Farmers	SPP	1, 3, 5
8.	Gary Condict	Sunflower Electric Power Corporation	SPP	1
9.	Louis Guidry	Cleco Power LLC	SPP	1, 3, 5
10.	Shawn Jacobs	Oklahoma Gas and Electric	SPP	1, 3, 5

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

11.	Stephen McGie	City of Coffeyville	SPP	NA
12.	Ron McIvor	Omaha Public Power District	MRO	1, 3, 5
13.	Kyle McMenamin	Xcel Energy	SPP	1, 3, 5, 6
14.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5
15.	Terri Pyle	Oklahoma Gas and Electric	SPP	1, 3, 5
16.	Sandra Sanscrainte	ITC holdings	SPP	NA
17.	Katie Shea	Westar Energy	SPP	1, 3, 5, 6
18.	Jamie Strickland	Oklahoma Gas and Electric	SPP	1, 3, 5
19.	Steven Stout	ITC holdings	SPP	NA
20.	John Zipp	ITC holdings	SPP	NA
21.	Brandon Desbrough	ITC holdings	SPP	NA
22.	Doug Jackson	Grand River Dam Authority	SPP	1, 3, 5
23.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
24.	Ashley Stringer	OMPA	SPP	4

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Kent Kujala	Detroit Edison			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Steven	Kerkmaz	RFC	3, 4, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Chang Choi	Tacoma Power	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
3.	Chris Mattson	City of Tacoma	WECC	5
4.	Michael Hill	Tacoma Public Utilities	WECC	

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Rhonda Bryant	El Paso Electric	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dennis Malone	El Paso Electric	WECC	1
2.	Tracy Van Slyke	El Paso Electric	WECC	3
3.	David Hawkins	El Paso Electric	WECC	5
4.	Tony Soto	El Paso Electric	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Terry L. Blackwell	Santee Cooper	X		X		X					

NERC

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Glenn Stephens	Santee Cooper	SERC	1
2.	Kevin Bevins	Santee Cooper	SERC	1
3.	Bridget Coffman	Santee Cooper	SERC	1
4.	Paul Camilletti	Santee Cooper	SERC	5
5.	S. T. Abrams	Santee Cooper	SERC	1

				1	2	3	4	5	6	7	8	9	10
10.	Group	Louis Slade	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tom Owens	ELECTRIC TRANSMISSION RELIABILITY	SERC	1, 3
2.	Rick Purdy	ELECTRIC TRANSMISSION RELIABILITY	SERC	1, 3
3.	Larry Whanger	F&H System	SERC	5
4.	Chip Humphrey	F&H Merchant	RFC	5

				1	2	3	4	5	6	7	8	9	10
11.	Group	Brenda Hampton	Luminant						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Laney	Luminant Generation Company LLC	ERCOT	5

				1	2	3	4	5	6	7	8	9	10
12.	Group	Joe Spencer	SERC Protection and Control Subcommittee (PCS)										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	George Pitts (Co-chair)	TVA	SERC	
2.	Stony Martin	Santee Cooper	SERC	
3.	Russ Evans	SCE&G	SERC	
4.	Paul Nauert (Co-chair)	Ameren	SERC	
5.	John Miller	GTC	SERC	
6.	Bridget Coffman	Santee Cooper	SERC	
7.	Jerry Blackley	Duke Energy	SERC	
8.	Rick Purdy	Dominion	SERC	
9.	Steve Edwards	Dominion	SERC	
10.	Joel Masters	SCE&G	SERC	
11.	David Fountain	Duke Energy	SERC	
12.	Phil Winston	Southern Co.	SERC	
13.	David Greene	SERC	SERC	

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

14.	Joe Spencer	SERC	SERC

				1	2	3	4	5	6	7	8	9	10
13.	Group	Ben Engelby	ACES Power Marketing Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
2.	Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3, 4
3.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
4.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5

				1	2	3	4	5	6	7	8	9	10
14.	Group	Jennifer Eckels	Colorado Springs Utilities	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Morland	Colorado Springs Utilities	WECC	1
2.	Charles Morgan	Colorado Springs Utilities	WECC	3
3.	Clint Jolly	Colorado Springs Utilities	WECC	6

				1	2	3	4	5	6	7	8	9	10
15.	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.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Utility Services	FRCC	3

				1	2	3	4	5	6	7	8	9	10
16.	Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates			X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brent Ingebrigtson	LG&E KU Services Company	SERC	3
2.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5
3.			WECC	5
4.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6
5.			NPCC	6

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

	Additional Member	Additional Organization	Region	Segment Selection
6.			SERC	6
7.			SPP	6
8.			RFC	6
9.			WECC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17. Group	Greg Rowland	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	RFC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18. Group	Larry Raczkowski	Project 2010-05.1	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	William Smith	FE	RFC	1
2.	Steve Kern	FE	RFC	3
3.	Doug Hohlbaugh	FE	RFC	4
4.	Ken Dresner	FE	RFC	5
5.	Kevin Querry	FE	RFC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19. Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dean	Bender	WECC	1
2.	Dan	Goodrich	WECC	1
3.	Fran	Halpin	WECC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20. Group	Greg Davis	GTC	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kevin Luke	GTC	SERC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
21. Group	Albert DiCaprio	ISO/RTO Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Greg Campoli	NYISO	NPCC	2
2.	Ben Li	IESO	NPCC	2
3.	Ali Miremadi	CAISO	WECC	2

Group/Individual	Commenter	Organization		Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
4. Stephanie Monzon	PJM	RFC	2										
5. Steve Myers	ERCOT	ERCOT	2										
6. Bill Phillips	MISO	RFC	2										
7. Charles Yeung	SPP	SPP	2										
22. Group	Scott Miller	MEAG Power		X		X		X					
Steve Jackson Steve Grego Danny Dees													
23. 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										
24. Group	Emily Pennel	Southwest Power Pool Regional Entity											X
No additional members listed.													
25. Individual	Heidt Melson	SPCWG			X								X
26. Individual	Ed Croft	Operational Compliance		X		X		X					
27. Individual	Sara McCoy	Electric Reliablity Compliance		X		X		X	X				
28. Individual	H. Pat Caldwell	TVA Transmission Operations and Maintenance		X									
29. Individual	Cole Brodine	Nebraska Public Power District		X		X		X					
30. Individual	Ryan Millard	PacifiCorp		X		X		X	X				
31. Individual	Brandy A. Dunn	Western Area Power Administration		X					X				
32. Individual	Antonio Grayson	Southern Company		X		X		X	X				
33. Individual	Dale Dunckel	Okanogan PUD		X									
34. Individual	Si Truc PHAN	Hydro-Quebec TransEnergie		X									
35. Individual	Michael Jones	National Grid		X		X							
36. Individual	Michael Moltane	ITC		X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
37.	Individual	Terri Pyle	Oklahoma Gas & Electric	X		X		X					
38.	Individual	Paul Haase	seattle city light	X		X	X	X					
39.	Individual	Louis C. Guidry	Cleco Corporation	X		X		X	X				
40.	Individual	NICOLE BUCKMAN	ATLANTIC CITY ELECTRIC COMPANY			X							
41.	Individual	Michael Mayer	Delmarva Power & Light Company			X							
42.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
43.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
44.	Individual	Bill Middaugh	Tri-State G&T	X									
45.	Individual	John Canavan	NorthWestern Energy	X									
46.	Individual	Jack Stamper	Clark Public Utilities	X									
47.	Individual	Thad Ness	American Electric Power	X		X		X	X				
48.	Individual	Anthony Jablonski	ReliabilityFirst										X
49.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
50.	Individual	Robert Dintelman	Utility System Efficiencies, Inc.										
51.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X					
52.	Individual	Timothy Brown	Idaho Power Co.	X		X							
53.	Individual	Angela Gaines (for Kellie Cloud)	Portland General Electric Company	X		X		X	X				
54.	Individual	Martyn Turner	LCRA Transmission Services Corporation	X									
55.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP					X					
56.	Individual	Saul Rojas	New York Power Authority	X		X		X	X				
57.	Individual	Mark F. Draper	Exelon Corp.	X		X		X	X				
58.	Individual	Mark R. Jones	Potomac Electric Power Company			X							
59.	Individual	Mike Weir	Dairyland Power Cooperative	X		X		X					
60.	Individual	Marie Knox	MISO		X								
61.	Individual	David Burke	Orange and Rockland Utilities	X		X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
62.	Individual	Melissa Kurtz	US Army Corps of Engineers	X				X					
63.	Individual	Thomas Foreman	Lower Colorado River Authority					X					
64.	Individual	Jim Cyrulewski	JDRJC Associates								X		
65.	Individual	Laurie Williams	Public Service Company of New Mexico	X		X							
66.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
67.	Individual	Don Jones	Texas Reliability Entity										X
68.	Individual	d mason	HHWP					X					
69.	Individual	Jonathan Appelbaum	The United Illuminating Company	X									
70.	Individual	Ed O'Brien	Modesto Irrigation District			X	X		X				
71.	Individual	Martin Bauer	US Bureau of Reclamation					X					
72.	Individual	Christina Koncz	PSEG	X		X		X	X				
73.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
74.	Individual	Andrew Z.Pusztai	American Transmission Company	X									
75.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X		X		X	X				
76.	Individual	Clay Young	South Carolina Electric and Gas	X		X		X	X				
77.	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	X		X		X	X				
78.	Individual	J. S. Stonecipher, PE	City of Jacksonville Beach, FL dba/ Beaches Energy Services	X								X	
79.	Individual	Eric Salsbury	Consumers Energy			X	X	X					
80.	Individual	Mike Hirst	Cogentrix Energy, LLC					X					
81.	Individual	O J Garcia	City of Homestead			X							
82.	Individual	Michael Falvo	Independent Electricity System Operator		X								
83.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X	X				
84.	Individual	Daniela Hammons	CenterPoint Energy	X									
85.	Individual	Bill Fowler	City of Tallahassee			X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
86.	Individual	Kirit Shah	Ameren	X		X		X	X				
87.	Individual	Scott Langston	City of Tallahassee	X									
88.	Individual	Scott Berry	Indiana Municipal Power Agency	X		X	X	X	X				
89.	Individual	Ronald L Donahey	Tampa Electric Company										
90.	Individual	Brian.J.Murphy	NextEra Energy Inc.	X		X		X	X				
91.	Individual	David Jendras	Ameren Services	X		X		X	X				
92.	Individual	Patrick Brown	Essential Power, LLC					X					
93.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
94.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
95.	Individual	Alice Ireland	Xcel Energy	X		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).

Organization	Yes or No	Entity Name
MEAG Power, Steve Jackson, Steve Grego, Danny Dees	Agree	OPPD
SPCWG	Agree	
Electric Reliablity Compliance	Agree	Lower Colorado River Authority (LCRA)
Hydro-Quebec TransEnergie	Agree	NPCC
Oklahoma Gas & Electric	Agree	Southwest Power Pool
ATLANTIC CITY ELECTRIC COMPANY	Agree	PEPCO HOLDINGS INC AND AFFILIATES
Delmarva Power & Light Company	Agree	Pepco Holdings Inc. and Affiliates
Lincoln Electric System	Agree	Midwest Reliability Organization NERC Standards Review Forum (MRO NSRF)
Potomac Electric Power Company	Agree	Pepco Holdings Inc. and Affiliates
US Army Corps of Engineers	Agree	MRO NSRF
Lower Colorado River Authority	Agree	Lower Colorado River Authority Segment 1
JDRJC Associates	Agree	Midwest ISO

Organization	Yes or No	Entity Name
HHWP	Agree	NAGFI wanted to provide additional comment related to the implementation plan and was unable to undue the "Agree" radio button We believe that the six-month implementation timeline is insufficient for many small entities to revise existing misoperations identification and analysis procedures and provide appropriate training to relevant staff. We also would like to see all implementation plans include training key Standard requirements or changes, and CEA expectations for basic compliance.
Response: Thank you for your comment. This requires discussion and coordination with the responses to question 8.		
American Transmission Company	Agree	ATC endorses and agrees with comments submitted by the MRO NSRF.
South Carolina Electric and Gas	Agree	SERC PCS
City of Homestead	Agree	FMPA
Ameren	Agree	

1. **The definition of "Misoperation" has been revised from the initial posting. Do you agree with the revised definition? If not, please provide specific suggestions for improvement.**

Summary Consideration:

Several commenters asked the drafting team to define and use the term 'composite Protection System' in the standard. To address these comments, the drafting team clarified the Misoperation definition by modifying the introductory sentence of the definition to indicate that a Misoperation pertains to the 'composite Protection System'. The Guidelines and Technical Basis section of the draft standard was also updated to explain that the 'composite Protection System' for an Element is its total complement of protection.

Several commenters suggested that the parenthetical phrases were subordinate in the categories listed in the Misoperation definition. The drafting team responded by removing the parentheses around the exclusionary phrases.

Several commenters questioned the range of activities included in the reference to "on-site" activities as used in the definition. In regards to part 6 of the definition (Unnecessary Trip - Other Than Fault), the drafting team explained that "on-site" refers to on-going activities at BES Facilities. However, it was made clear that once the activities have been completed and the equipment released from service, the exclusion regarding "on-site" activities no longer applies regardless of the presence of personnel at the location. "Inspection" was added to the list of "on-site" activities that could initiate an operation but should exclude it from being considered a Misoperation.

Some commenters questioned category 5 of the definition (Unnecessary Trip - During Fault). These commenters asked for clarity on the exclusionary phrase and suggested that the word "adjacent" be removed or replaced. The drafting team revised category 5 of the Misoperation definition to remove mention of exclusions.

One commenter asked for the exclusionary phrase in category 3 of the definition (Slow Trip - During Fault) to be expressed in a way that was more consistent with the rest of the definition. The drafting team revised category 3 to be similar to the first two parts of the definition.

A few commenters questioned whether Underfrequency Load Shedding (UFLS) was covered by the standard. The drafting team clarified the issue by modifying the 'included' Facilities portion of the Applicability section to specifically include Underfrequency Load Shedding (UFLS) that trips a BES Element.

Several commenters asked for clarification regarding the phrase "slower than intended" in categories 3 and 4 of the definition. The drafting team explained that the phrase means that the Protection System operated slower than the objective of the owner(s).

Several commenters questioned the reference to the TPL standards in the definition. The drafting team explained that the reference (made in category 3 of the definition) 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 indicate stability, thermal and voltage limits and loss of Demand impacts for contingencies and are found in Table 1 of those standards.

Some commenters expressed concerns regarding the extent of non-Fault conditions. The drafting team advised that the examples used in categories 2 and 4 of the definition were not meant to be an all-inclusive list.

Several commenters preferred a shorter, simpler definition. The drafting team declined to make the suggested changes because a brief definition could be open to varying interpretations due to lack of detail.

Several commenters asked to exclude weather events and other unusual conditions from consideration. The drafting team explained that it would not be prudent to simply ignore operations that occurred during large storms. Further, the Sanction Guidelines of the North American Electric Reliability Corporation allows the entity to be afforded more time for unusual events.

Organization	Yes or No	Question 1 Comment
Western Small Entity Comment Group	No	The comment group is concerned with the use of the phrase “slower than intended” in definition 4. The actual intended speed of operation is/was in the mind of the protection engineer who may not necessarily be available to testify regarding his intent for every fault. Settings documentation generally does not show speed of operation, only set points and manufacturer curves. A speed of operation may be derived from these settings right down to the millisecond, but the protection engineer did likely count on this level of precision after considering CT and relay measurement error and coordinating margin. Lacking a tolerance, the documented settings do not fully show the “intent.” In addition the documentation itself may be in error and possibly be the cause of a misoperation (although not by this definition if we use the document to gage intent). Entities and Compliance Enforcement will need more guidance from the drafting team on just how to measure “slower than intended”, and to understand just how slow that is. In the end, however, it is not the intended speed that matters, it is the result. The parenthetical suggests it is the result that counts, but we don’t see the parenthetical overruling the “slower than intended” language. Slow Trip - During Fault - A slow Protection System

Organization	Yes or No	Question 1 Comment
		operation for a Fault within the zone it is designed to protect, resulting in miscoordination with other Protection Systems or failure to meet the performance requirements of the TPL standards.
Response: Thank you for your comments. **The phrase "slower than intended" in parts 3 and 4 of the definition mean that the Protection System operated slower than the objective of the owner(s). 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 any additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate. The parenthetical phrases are part of the definition and meant to clarify parts of the definition. The parentheses will be removed so that these phrases are not seen as subordinate to other parts of the definition. The suggested change to part 3 of the definition changes the meaning by overstating the intent of the exclusionary phrases. This would weaken the language and allow the failure of certain required high-speed Protection Systems to be not classified as a Misoperation.**		
Pepco Holdings Inc & Affiliates	No	The existing definition of misoperation in the NERC Glossary of Terms indicates that if any individual component of a Protection System fails it is considered a misoperation. This new PRC-004-3 proposed definition modifies the definition by treating the primary and back-up protection schemes protecting a circuit element as a composite protective system. Individual component failures would not be considered a misoperation if the "overall performance of the composite Protective System for an element is correct." We support this intent, but feel that the present wording in the proposed misoperation definition is not clear enough to adequately emphasize this distinction. The capitalized term Protection System, which is a NERC defined term, is used throughout this standard. However, the applicability of the proposed misoperation definition applies to the "Composite Protective System", and not to each of the primary and backup Protection Systems individually. This point must be made very clear in the misoperation definition, since it is the foundation of the

Organization	Yes or No	Question 1 Comment
		requirements in PRC-003-4. As such, either a new term "Composite Protective System" needs to be defined and the language in the misoperation definition and PRC-004-3 changed to reference this term; OR a qualifying paragraph could be included within the misoperation definition that states that "In the context of this misoperation definition a Protective System is considered to be the entire complement of protective system components (including both primary and backup protection systems) designed to protect a circuit Element."
Response: Thank you for your comments. **It is preferable not to add more definitions to the NERC Glossary of Terms, instead the drafting team modified the Guidelines and Technical Basis section to include the following: "The composite Protection System in the context of this standard is the total complement of protection for a system Element (line, bus, transformer, generator, etc). Primary and secondary protection of a given Element is considered as the composite Protection System, not two separate Protection Systems." The drafting team also changed the introductory sentence of the definition to the following based on your comment: "The failure of an Element's composite Protection System to operate as intended."**		
Souhwest Power Pool Reliability Standards Development Team	No	We need some clarification around section 3 Slow Trip During Fault. Is this intended to address the future changes around the Upcoming TPL standards? We need clarification on what is meant by referencing the TPL performance Standards in this section.
Response: Thank you for your comments. **No, the reference to the TPL standards is not related to the upcoming changes to these standards. The reference to the TPL standards is meant to place some bounds on the time to clear a Fault and prevent dynamic instability.**		
Detroit Edison	No	No, Dteroit Edison disagrees with "Slow Trip - Other than Fault." We feel that the SDT should consider, with respect to many of the Generating Unit trip conditions that are given, that there may not be adequate resolution of time and current\voltage\etc. monitoring. If monitoring with as fine a

Organization	Yes or No	Question 1 Comment
		resolution as is required to analyze speed of operation, it should not be considered a misoperation.
Response: Thank you for your comments. **The standard and Misoperation definition do not require any additional monitoring be installed. Each entity must review each of its Protection System operations and determine whether the operation should be categorized as a slow trip - other than Fault Misoperation based on its available information.**		
Tacoma Power	No	1) It is still not completely clear what is meant by 'intended'? 2) The wording for Slow Trip - During Fault is awkward. For example, consider changing "...if high-speed performance is required to meet the performance requirements of the TPL standards or by coordination requirements with other Protection Systems" to "...if high-speed performance is required to meet the performance requirements of the TPL standards or coordination requirements with other Protection Systems"; in other words, remove 'by.' 3) Under the proposed, revised definition of a Mis-operation, it is unclear if a Mis-operation resulting from mis-coordinated relays would normally be categorized as Slow Trip or Unnecessary Trip. 4) What is meant by 'on-site,' as in the definition of Unnecessary Trip - Other Than Fault? Specifically, what if a remote terminal is inadvertantly tripped by means of a communications system during maintenance, testing, construction, or commissioning activities; technically, the interrupting device that operated is not "on-site." 5) Additionally, what if an operation occurs during initial energization or loading following maintenance, testing, constuction, or commissioning; it seems that because the operation occurs with personnel still on site that this should not be considered a reportable Mis-operation, especially since

Organization	Yes or No	Question 1 Comment
		the Element is just being returned to service.
Response: Thank you for your comments. **1) The word "intended" as used in the definition refers to whether the Protection System performance met the objectives of the owner(s).** **2) Removing the word "by" does not improve the wording. If the word "by" is removed, other wording would need to be changed. An alternative could be the following: "…if high-speed performance is required to meet the performance requirements of the TPL standards or to coordinate with other Protection Systems."** **3) It depends on the miscoordination. If the Misoperation occurred because the Protection System for the faulted Element operated slower than intended, then it is a Slow Trip – During Fault. If the Misoperation occurred because a Protection System for another Element operated faster than intended, then it is an Unnecessary Trip – During Fault.** **4) "On-site" refers to on-going activities at BES Facilities. This is the opposite of "as left" conditions where some activities were completed and personnel left the Facilities. The inadvertent operation to a remote terminal via communications would be the result of an "on-site" activity.** **5) Once the equipment has been returned or released to service, or the inspection has been completed, it would be considered a Misoperation regardless of the presence of the technical personnel.**		
Santee Cooper	No	While the purpose of the clarifications in the misoperation definition is understood, the proposed definition seems to use the term "non-fault condition" differently in different sections. For items 2 and 4, it says "a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, overexcitation, or loss-of-excitation." Similar wording is used in 4 "such as a power swing, under-voltage, overexcitation, or loss-of-excitation. However, in 6, the terms "other than fault" and "non-fault condition" are also used, but, it would be expected that the definition here should be broader than in 2 and 4, to include when a misoperation occurs for no reason (no abnormal condition). It seems like this could lead to a misinterpretation of number 6, since it uses the same

Organization	Yes or No	Question 1 Comment
		term “non-fault condition” as in 2 and 4.We suggest having the following 4 categories, which would still ensure that the “non-fault conditions” are still included:1. Failure to Trip - A failure of a Protection System to operate for a Fault within the zone it is designed to protect or for a non-fault condition (such as a power swing, under-voltage, over excitation, or loss of excitation) for which the Protection System was intended to operate.2. Slow Trip - A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect or for a non-Fault condition such as a power swing, under-voltage, over excitation, or loss of excitation.3. Unnecessary Trip - A Protection System operation for a Fault or for a non-fault condition (such as a power swing, under-voltage, over excitation, or loss of excitation) for which the Protection System is not intended to operate. This excludes any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone.4. Unnecessary Trip - Normal system conditions - A Protection System operation when no fault or non-fault conditions are present (such as a power swing, under-voltage, over excitation, or loss of excitation).There may be other appropriate wordings for number 4.
Response: Thank you for your suggestion. **The drafting team believes the non-Fault condition phrase is used consistently in categories 2, 4, and 6. The non-Fault conditions cited in categories 2 and 4 are examples and do not constitute an all inclusive list.**		
Dominion	No	a). Under Definitions of Terms Used in the Standard, #3 indicates that delayed clearing of a high speed protection system is a Misoperation if it does not meet TPL requirements or coordination requirements. The specific requirements being referred to are unclear and non specific. Is the intent to report failure of high speed tripping for those Protection Systems that impact system stability? Suggest that more clarity be given to the requirement references.

Organization	Yes or No	Question 1 Comment
		b). Under Definitions of Terms Used in the Standard, #5 change definition to read - Unnecessary Trip - During Fault - A Protection System operation for a Fault for which the Protection System is not intended to operate, excluding properly coordinated remote trips when the local Protection System fails to clear the Fault. c). In the Application Guide - Guidelines and Technical Basis, under the definitions there appears to be more emphasis on Generation related examples. Recommend a balance of both Generation and Transmission examples in this guide.
Response: Thank you for your comments. **a) The performance requirements in the TPL standards are found in Table 1. While system stability is often the primary concern, there are thermal and voltage limits and loss of Demand impacts that need to be met as well. The coordination requirements with other Protection Systems does not refer to requirements listed in standards but the need to ensure that relaying operates in the proper or planned sequence (i.e. the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).** **b) The drafting team modified category 5 of the definition and believes it addresses your concern.** **c) A review of the examples shows that they are evenly split between Generation and Transmission examples. Categories 2 and 4 of the definition which involve failure to trip and slow trip during non-Fault conditions are somewhat more relevant to generators as line and transformer protection is predominately for detecting Faults.**		
Luminant	No	Misoperations categorized in line items #3 and #4 are subjective and left up to varying interpretation for protective systems on generator applications. Unlike the definition for “Slow Trip - During Fault”, Transmission Owners are provided with criteria that define a slow operation while generation owners do not have similar established criteria for trips involved in items #3 or #4. Luminant recommends line item #4 be removed since it is subject to varying interpretations and item #3 be only applicable to Transmission.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. **The drafting team does not believe that categories 3 and 4 are subjective. It is true that entities will have varying capabilities in determining whether an operation was slow or not but that is not a subjective issue. The standard and Misoperation definition do not require any additional monitoring to be installed. Each entity must review each of its Protection System operations and determine whether an operation is a Misoperation based on the available information. The drafting team believes that it does not serve the interest of BES reliability by basing analysis capabilities on the minimum monitoring that any entity may have at its disposal. The criteria for category 3 are also applicable to Generation Owners. In particular, the Protection Systems for a generation Facility need to coordinate with other Protection Systems. The phrase "slower than intended" in categories 3 and 4 of the definition mean that the Protection System operated slower than the objective of the owner(s). 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 any additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate. The drafting team will enhance the Guidelines and Technical Basis section with this information.**		
Florida Municipal Power Agency	No	1) The description of "unnecessary trip", the exclusion of remote protection System operation is not accurate because such operation is actually necessary (not "unnecessary") and it is intended to operate for failure or slow operation of local Protection Systems. 2) The description for a remote back-up system operation and limimting that to only the "adjacent" zone is not appropriate. There are cases when the appropriate protection system operation may not be from the "adjacent" zone of protection. 3) Also, the term "zone of protection" is not defined, e.g., are zone 1, zone 2 and zone 3 distance relays different "zones of protection". If a zone 3 relay covers two transmission facilities, is that one and the same "zone of protection"? Or does the SDT intend a zone to be breaker-to-breaker? How is a circuit swithcher treated when defining a zone of protection>? Etc.

Organization	Yes or No	Question 1 Comment
		4) The description of a "slow trip" as "operation slower than intended" without some sort of quantification of how much slower than intended is ambiguous (e.g., is one cycle longer delay than expected a misoperation?), unless the intent is to establish an operating time as the slowest intended operating time. Even so, measurability becomes a concern.
Response: Thank you for your comments. **1) The drafting team revised category 5 of the Misoperation definition to remove mention of exclusions.** **2) The drafting team agrees. In most cases a proper remote backup operation is in an adjacent zone. The language in Category 5 was changed to cover non-adjacent operations.** **3) The term "zone of protection" is not used in the definition. This widely used term has been defined by other literature and does not require further clarification in this standard. A reference the commenter can use to clarify the term is the "IEEE Guide for Protective Relay Applications to Transmission Lines", IEEE Std C37.113-1999 (or later revisions if available).** **4) The phrase "slower than intended" in categories 3 and 4 of the definition mean that the Protection System operated slower than the objective of the owner(s). 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 any additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate.**		
Duke Energy	No	Duke Energy does not agree with the wording in Part 3 of the definition of Misoperation. "3. Slow Trip - During Fault" identifies "Delayed Fault clearing associated with an installed high speed protection scheme" as a Misoperation, "if the high-speed performance is required to meet the performance requirements of the TPL standards". The TPL standards do not currently contain any high-speed performance requirements, and Transmission Planners must plan to meet Category C "Single Line to Ground Faults" with delayed clearing. We suggest the following alternative wording which removes the linkage to TPL standards, and puts "3. Slow Trip - During

Organization	Yes or No	Question 1 Comment
		Fault" on the same footing as "1. Failure to Trip - During Fault" and "2. Failure to Trip - Other Than Fault":"3. 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 as long as the overall performance of the Protection System for an Element is acceptable, and the high-speed performance is not required for coordination with other Protection Systems.)
Response: Thank you for your comments. **The drafting team disagrees with your suggested wording because there is no indication as to what is considered acceptable performance. The performance requirements in the TPL standards are found in Table 1 are applicable to all contingencies mentioned for Type A, B and C contingencies and state: System Stable and both Thermal and Voltage Limits within Applicable Rating Specifically, the performance requirements are dynamic performance requirements and are typically met by requiring installation of high-speed protection.**		
JEA	No	JEA suggests a shorter definition such as: either the operation of a protection system when it should not or the failure to operate when it should.
Response: Thank you for your comments. **The drafting team believes the existing definition sufficiently describes the term of Misoperation providing enough detail to be unambiguous. 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 also provides none of the specific exceptions that have been cited in the 6 categories. Unfortunately, the brief definition leaves it open to interpretations because of its lack of detail.**		
Nebraska Public Power District	No	I recommend adding the underlined text to the misoperation definitions for items: 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

Organization	Yes or No	Question 1 Comment
		scheme is a Misoperation if the high-speed performance is required to meet the performance requirements of the TPL standards or by coordination requirements with other Protection systems for a reasonable number of system contingencies. Unnecessary Trip - During Fault - A Protection System operation for a Fault for which the Protection System is not intended to operate for a reasonable number of system contingencies, excluding any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone. Perhaps the number of contingencies should be a set number such as one so that for non standard system configurations where coordination may be lost. For example, such as multiple ground sources being out of service causing ground overcurrent miscoordination in part of the system.
Response: Thank you for your comments. **Unfortunately, a "reasonable number of system contingencies" is ambiguous and its use in the standards would complicate enforcement. It would also be difficult to decide on a single number that would be appropriate for all cases.**		
Southern Company	No	1) Instead of clarification and specification, the objective of the change to the definition should be simplification. A simpler definition could be: Failure of a Protection System to operate as intended, evidenced by it not operating when it should have, operating when it should not have, or operating slower than it was intended to operate. 2) If the definition remains in the present form, we would suggest slight changes to language on #1 and #2: (The failure of........of the Protection System for the element it is designed to protect is correct.) 3) Suggest slight changes to language on #3: (Delayed Fault clearing ....high-speed performance has been identified as required......) 4) Please clarify why # 3 and # 4 are not a subset of # 1.If not, it should be

Organization	Yes or No	Question 1 Comment
		made clear in the verbiage.
Response: Thank you for your comments. **1) Although a shorter definition has many 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 also provides none of the specific exceptions that have been cited in the 6 categories. Unfortunately, the brief definition leaves it open to interpretations because of its lack of detail.** **2) The drafting team agrees and believes the suggested change adds clarity, the definition was changed.** **3) The drafting team agrees and believes the suggested change adds clarity, the definition was changed.** **4) Categories 3 and 4 are slow trips, not a failure to trip. For example, the local Protection System may have operated and initiated a trip but not before a remote Protection System operated. Also category 4 is for a non-Fault condition where category 1 is specifically for a Fault condition.**		
ITC	No	1) For 1 through 3, The definitions should be revised to remove the need for the clarifications in parenthesis. One such revision should include clarifying the scope of a 'Protection System.' It is not clear whether multiple protection schemes for a single element would be considered one 'Protection System' or if each scheme is considered a 'Protection System'. It may require clarifying the definition of 'Protection System' within NERC Glossary or addressing directly in this standard. 2) What is the definition of 'slow?' Is it only defined by TPL standards or expected operation time designed into the 'Protection System?'
Response: Thank you for your comments. **1) The parentheses have been removed per comments received. The drafting team changed the introductory sentence of the definition to the following based on comments and should address the multiple schemes issue that you brought up: "The failure of an Element's composite Protection System to operate as intended."** **2) The term "slow" is not defined in this or the TPL standards or the NERC Glossary of Terms. In the definition, it is stated that**		

Organization	Yes or No	Question 1 Comment
"…operation that is slower than intended…" The phrase "slower than intended" means that the Protection System operated slower than the objective of the owner(s). 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 any additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate.		
Cleco Corporation	No	Need clarification on what is meant by referencing the TPL performance standards in section 3.
Response: Thank you for your comment. **The reference to the TPL standards is meant to place some bounds on the time to clear a Fault. The performance requirements in the TPL standards are found in Table 1 are applicable to all contingencies mentioned for Type A, B and C contingencies and state: System Stable and both Thermal and Voltage Limits within Applicable Rating Specifically, the performance requirements are dynamic performance requirements and are typically met by requiring installation of high-speed protection.**		
Manitoba Hydro	No	1) Although we agree with most components of the definition, it is not clear to us what constitutes a "Failure to Trip". For example, in cases of redundant "A" and "B" protection systems, if the "A" protection trips, but the "B" protection does not trip, would this be a misoperation reportable as a "Failure to Trip"? 2) The first sentence of the second last paragraph of section A is not clear:"Misoperation of or associated with Special Portection schemes ...."
Response: Thank you for your comments. **1) No, because there is redundancy in the composite Protection System, the overall performance would not be impacted.** **2) The sentence is simply indicating that the Misoperations of SPSs, RASs and UVLSs are not addressed in this version of the standard.**		

Organization	Yes or No	Question 1 Comment
Tri-State G&T	No	1) We understand why the parenthetical expressions are included in the first two parts of the definition since they clarify what is excluded from the definition. However, the parenthetical phrase in the third part of the definition seems to be another expression of what is to be considered a Misoperation, but it is not consistent with the non-parenthetical definition. We suggest changing it to "Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance is not used to meet the performance requirements of the TPL standards nor is it required to ensure coordination with other Protection Systems." 2) We have a question regarding the phrasing "required to meet the performance requirements of the TPL standards" (changed in our recommended language). Does this mean that a simulation has been performed that determines that high speed protection is required to meet TPL standard requirements? Or does it apply to the slower clearing if the reduced performance results in a failure to meet the requirements of the TPL standards regardless of whether it had been discovered and documented? 3) While we did not base our "No" answer on the following, our belief is that the exclusions of individual Protection System component failures as long as the total Protection System operates to clear the Fault in the time and zone for which it was designed may lead to a reduced level of reliability to the BES. Failures of components may be easily overlooked if the entity doesn't review the event closely enough to discover misoperating components because the aggregate system operated correctly. But we recognize that there is unclarity regarding the definition of Protection System and that unclarity could lead to considering the overall performance of the aggregate Protection System, which was the interpretation used by the drafting team.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. **1) The drafting team made the suggested change to promote consistency in the definition.** **2) The drafting team revised Category 3 based on comments to clarify that high-speed performance has been identified.** **3) The exclusions of component failures as long as the total Protection System operates correctly were based on recommendations by the NERC SPCS. Entities still need to review each Protection System operation. The difficulty in requiring the investigation of component failures and the development and completion of associated CAPs is the additional administrative burden for a type of failure that had no immediate reliability impact for an event that revealed it.**		
Flathead Electric Cooperative, Inc.	No	We are concerned about what "Slow" is and if the drafting committee is creating a new kind of misoperation or whether this is something that might just be found as a result an investigation of an existing type of misoperation.
Response: Thank you for your comments. **The IEEE/PSRC I3 Working Group on 'Transmission Protective Relay System Performance Measuring Methodology' developed categories of Relay System Misoperation including "Slow Trip" in 1999. Most of the Regional Entities did have a category of Misoperation called "Slow Trip." So, the terminology has existed for some time. All Misoperations require some amount of investigation. It is also likely that some investigation would be required to determine, for example, if the local protection was slow or the remote protection tripped unnecessarily (because it was too fast or did not receive a blocking signal, etc.).**		
Dairyland Power Cooperative	No	The SDT should clarify whether UFLS is or is not covered by this standard. The "Consideration of Comments" indicates that it is. If so, it is suggested that the SDT consider adding underfrequency to the list of non-Fault conditions listed in items 2. and 4. in the Misoperation definition. If not, it would help to clearly state that it is "excluded" in Section 4.2.2.
Response: Thank you for your comments. **UFLS that trip the BES are covered by PRC-004-3. For clarity, the drafting team added the following in the included Facilities**		

Organization	Yes or No	Question 1 Comment
portion of the Applicability section 4.2.2 in the draft standard "Underfrequency Load Shedding (UFLS) that trips a BES Element". UFLS events can be triggered by Faults or non-Fault conditions. Not all non-Fault conditions are (or probably could be listed) with the examples in categories 2 and 4 of the Misoperation definition.		
MISO	No	The SDT should clarify whether UFLS is or is not covered by this standard.
Response: Thank you for your comments. **UFLS that trip the BES are covered by PRC-004-3. For clarity, the drafting team added the following in the included Facilities portion of the Applicability section 4.2.2 in the draft standard "Underfrequency Load Shedding (UFLS) that trips a BES Element". UFLS events can be triggered by Faults or non-Fault conditions. Not all non-Fault conditions are (or probably could be listed) with the examples in categories 2 and 4 of the Misoperation definition.**		
City of Austin dba Austin Energy	No	The parenthetical at the end of the two "Failure to Trip" categories is not clear. Austin Energy requests the SDT to consider including some of the detail in the Guidelines and Technical Basis section on page 15 of the clean draft.
Response: Thank you for your comments. **The parentheses were removed and the language was further modified for clarity. The exclusions of component failures as long as the total Protection System operates correctly were based on recommendations by the NERC SPCS. The drafting team believes the Applications Guide section is the proper location to document drafting team intent.**		
Texas Reliability Entity	No	(1) Failure to Trip During Fault: The statement "(The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for an Element is correct.) " is somewhat vague and open to interpretation. We understand the purpose of this language as stated in the Guidelines and Technical Basis, i.e. when a high speed zone element trips faster than a high speed pilot system. However, we have had instances in our Region where a high speed pilot system fails and the fault is subsequently cleared by a time-delayed zone

Organization	Yes or No	Question 1 Comment
		element, typically in 30-45 cycles rather than in 5 cycles or less. This instance could be interpreted as "correct overall performance" by the entity and not reportable. Is this the intent of the SDT? Or should this instance be recorded as a "Failure to Trip" or "Slow Trip During Fault"? The Guidelines and Technical Basis section offers some good examples, however, it should possibly be expanded to provide more discrete cases.(2) Failure to Trip Other than Fault: See comments under Failure to Trip During Fault(3) Slow Trip During Fault: See comments under Failure to Trip During Fault
Response: Thank you for your comments. **The exclusions of component failures as long as the total Protection System operates correctly were based on recommendations by the NERC SPCS. Entities still need to review each Protection System operation. The difficulty in requiring the investigation of component failures and the development and completion of associated CAPs is the additional administrative burden for a type of failure that had no immediate reliability impact for an event that revealed it. For the example cited, it appears that the operation would not be a Misoperation unless high-speed performance (as stated in category 3 of the definition) was required. If high-speed performance was required, then it would be an instance of "Slow Trip – During Fault".**		
Liberty Electric Power LLC	No	The "unnecessary trip- other than fault" should be removed. Standards should not cover balance of plant issues, which could be trip causes. While trip analysis is a best practice, it should not be a required, zero tolerance element of the NERC standards. For example, a turbine vibration fault could use the same 86 relay as the generator protection relay, which would make that 86 part of the protection system. Vibration trips of that 86 relay would then fall under the program, causing unneeded effort for compliance documentation of a straightforward balance of plant issue. The definitions themselves are overly complex, and could be combined in many cases.
Response: Thank you for your comments. **The drafting team Believes "Unnecessary Trip - Other Than Fault" should be kept to capture Protection System Misoperations that**		

Organization	Yes or No	Question 1 Comment
occur during non-fault conditions. Excluding this type of Misoperation would cause a reliability gap. PRC-004-3 requires any Protection System operation be reviewed to determine whether the Protection System operated as intended to isolate the generating unit from the BES. The activation of the vibration sensor is not required to be reviewed because only protective relays that respond to electrical quantities are included in the "Protection System" as defined in the NERC Glossary of Terms.		
City of Jacksonville Beach, FL dba/ Beaches Energy Services	No	1) The description of "unnecessary trip", the exclusion of remote protection System operation is not accurate because such operation is actually necessary (not "unnecessary") and it is intended to operate for failure or slow operation of Local Protection Systems. 2) The description for a remote back-up system operation and limiting that to only the "adjacent" zone is not appropriate. There are cases when the appropriate protection system operation may not be from the "adjacent" zone of protection. 3) Also, the term "zone of protection" is not defined, e.g., are zone 1, zone 2 and zone 3 distance relays different "zones of protection". If a zone 3 relay covers two transmission facilities, is that one and the same "zone of protection"? Or does the SDT intend a zone to be breaker-to-breaker? How is a Circuit Switcher treated when defining a zone of protection>? Etc. 4) The description of a "slow trip" as "operation slower than intended" without some sort of quantification of how much slower than intended is ambiguous (e.g., is one cycle longer delay than expected a misoperation?), unless the intent is to establish an operating time as the slowest intended operating time. Even so, measurability becomes a concern.
Response: Thank you for your comments. **1) The point the exclusion in category 5 was making is that the remote operation was necessary and, therefore, should not be consider a Misoperation. However, it would be clearer if this item was broken into two sentences to better emphasize your concern. The exclusionary phrase has been replaced with the following second sentence: "The operation of a remote**		

Organization	Yes or No	Question 1 Comment
Protection System is not a Misoperation if it operated as intended as a result of an interrupting device failure, or a failure to trip, or slow trip of a local Protection System for a faulted Element." **2) The drafting team agrees. In most cases a proper remote backup operation is in an adjacent zone. The language in Category 5 was changed to cover non-adjacent operations.** **3) The term "zone of protection" is not used in the definition. This widely used term has been defined by other literature and does not require further clarification in this standard. A reference the commenter can use to clarify the term is the "IEEE Guide for Protective Relay Applications to Transmission Lines", IEEE Std C37.113-1999 (or later revisions if available).** **4) The phrase "slower than intended" in categories 3 and 4 of the definition mean that the Protection System operated slower than the objective of the owner(s). 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 any additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate.**		
Consumers Energy	No	Protection Systems can be and are designed to provide remote backup protection for adjacent zones. In many instances, these zones are owned and operated by other entities. As worded, part 1 of the definition says "failure...to operate for a Fault within the zone it is designed to protect." If entity A has a Protection System that is designed to provide remote backup protection for entity B and entity B has a Fault on that Element, but does not notify entity A of said Fault, then without an interrupting device operation, entity A has no way of knowing if their Protection System should have operated or not.Proposed solution: Failure to Trip - During Fault - A failure of a Protection System to operate for a Fault within the zone it is designed to be the primary protection.
Response: Thank you for your comments. **The failure to trip of remote backup protection would be expected to result in a cascading outage or in equipment damage. PRC-004-3 would require the Protection System operations to be investigated by the owners, and would require the Misoperations to be mitigated. Excluding remote backup protection from PRC-004-3 would introduce a reliability gap. In your example, entity A**		

Organization	Yes or No	Question 1 Comment
would not be required to investigate the operation since they did not have an interrupting device operation unless entity B or some other entity notified them of a suspected Misoperation (see Requirement R1 part 1.1).		
Cogentrix Energy, LLC	No	The proposed definitions are unneccisarily complicated. Also, the "catch all" category "Unnecessary Tip - Other Than Fault" will cause entities to analyze, document and report events that may occur but were not due to issues in engineering, design, or relay settings, thus providing little to no benefit to industry to learn from the event. For example, a control wire that was chewed by a mouse and led to a line tripping out.
Response: Thank you for your comments. **The drafting team believes the existing definition sufficiently describes the term of Misoperation providing enough detail to be unambiguous. The drafting team believes "Unnecessary Trip - Other Than Fault" should be kept to capture Protection System Misoperations that occur during non-fault conditions. Excluding this type of Misoperation would introduce a reliability gap.**		
CenterPoint Energy	No	CenterPoint Energy recommends additional clarification be included in Item 5 ‘Unnecessary Trip - During Fault’ to address interrupter device problems that result in what is commonly referred to as a “stuck breaker”. The proposed definition provides only for excluding remote tripping from a failure to trip or slow trip of a Protection System; however, interrupting device problems - other that trip coils - can also result in a failure to trip or slow trip event. Remote tripping is commonly utilized for local breaker failure schemes and for remote backup clearing for such stuck breaker events. CenterPoint Energy recommends adding wording at the end of Item 5, resulting in the following wording for ‘Unnecessary Trip - During Fault’: “A Protection System operation for a Fault for which the Protection System is not intended to operate, excluding any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone or from a failure to trip or slow trip of an interrupting device.”

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. **Category 5 of the definition was modified as follows and should address your comments: "Unnecessary Trip - During Fault - A Protection System operation for a Fault for which the Protection System is not intended to operate. The operation of a remote Protection System is not a Misoperation if it operated as intended as a result of an interrupting device failure, a failure to trip of a local Protection System or slow trip of a local Protection System for a faulted Element."**		
City of Tallahassee	No	The comment 'The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for an Element is correct' could be clearer. Perhaps stating 'The failure of a Protection System component is not a Misoperation as long as the Protection System operated for the fault within the zone it is designed to protect. Also, a distinction should be made whether a misoperation that only interrupts distribution and not transmission is a reportable misoperation. Example of what I am referring to is if a transformer relay trips a high side breaker but does not interrupt the BES, only distribution load.
Response: Thank you for your comments. **The exclusions of component failures as long as the total Protection System operates correctly were based on recommendations by the NERC SPCS. Entities still need to review each Protection System operation. The difficulty in requiring the investigation of component failures and the development and completion of associated CAPs is the additional administrative burden for a type of failure that had no immediate reliability impact for an event that revealed it. Section 4.2.1 of the Applicability section specifies that PRC-004-3 is applicable only to Protection Systems for Facilities that are part of the BES. PRC-004-3 is not applicable in the cited transformer relaying event because the transformer relay tripped only non-BES Elements.**		
Indiana Municipal Power Agency	No	Indiana Municipal Power Agency agrees with the comments submitted by Florida Municipal Power Agency (FMPA).
Response: Please see the responses to comments by FMPA.		

Organization	Yes or No	Question 1 Comment
Tampa Electric Company	No	1) The description of “unnecessary trip”, the exclusion of remote protection System operation is not accurate because such operation is actually necessary (not “unnecessary”) and it is intended to operate for failure or slow operation of local Protection Systems. 2) The description for a remote back-up system operation and limimting that to only the “adjacent” zone is not appropriate. There are cases when the appropriate protection system operation may not be from the “adjacent” zone of protection. 3) Also, the term “zone of protection” is not defined, e.g., are zone 1, zone 2 and zone 3 distance relays different “zones of protection”. If a zone 3 relay covers two transmission facilities, is that one and the same “zone of protection”? Or does the SDT intend a zone to be breaker-to-breaker? How is a circuit swithcher treated when defining a zone of protection>? Etc. 4) The description of a “slow trip” as “operation slower than intended” without some sort of quantification of how much slower than intended is ambiguous (e.g., is one cycle longer delay than expected a misoperation?), unless the intent is to establish an operating time as the slowest intended operating time. Even so, measurability becomes a concern.

Response: Thank you for your comments.

1) **The drafting team revised category 5 of the Misoperation definition to remove mention of exclusions.**

2) **The drafting team agrees. In most cases a proper remote backup operation is in an adjacent zone. The language in Category 5 was changed to cover non-adjacent operations.**

3) **The term “zone of protection” is not used in the definition. This widely used term has been defined by other literature and does not require further clarification in this standard. A reference the commenter can use to clarify the term is the “IEEE Guide for Protective Relay Applications to Transmission Lines”, IEEE Std C37.113-1999 (or later revisions if available).**

Organization	Yes or No	Question 1 Comment
4) The phrase “slower than intended” in categories 3 and 4 of the definition mean that the Protection System operated slower than the objective of the owner(s). 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 any additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate.		
Ameren Services	No	(1) We suggest, In #3 Slow Trip, to replace “or by coordination requirements with other Protection Systems” with “or to meet the coordination requirements with other Protection Systems in accordance with applicable PRC standards.” For example, entities regularly install one pilot relaying system on a line for other reasons, such as end use power quality. The failure of such a pilot relaying system to trip high speed should not be classified as a Misoperation. (2) We suggest to insert “the operation” to clarify #6 yielding “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 operation is unrelated to on-site maintenance, testing, construction or commissioning activities.”
Response: Thank you for your comments. **1. The need to coordinate Protection Systems is not limited to requirements in the PRC standards. The drafting team does not believe there is a need to reference the PRC standards. The drafting team agrees with you that in the example you cite, a failure of the pilot relaying system would not be a Misoperation as it was not required to meet TPL performance requirements.** **2. The drafting team does not believe the insertion of the words “the operation” adds additional clarity to category 6.**		
Essential Power, LLC	No	1) The proposed definitions are unnecessarily complicated. 2) Also, the "catch all" category "Unnecessary Trip - Other Than Fault" will cause entities to analyze, document and report events that may occur but were not due to issues in engineering, design, or relay settings, thus

Organization	Yes or No	Question 1 Comment
		providing little to no benefit to industry to learn from the event. For example, a control wire that was chewed by a mouse and led to a line tripping out. 3) We would also like to see language that addresses an “Unnecessary Trip-During Fault - A Protection System operation for a Fault for which the Protection System is intended to operate, but operates prior to the required element setting.”
Response: Thank you for your comments. **1) The drafting team believes the existing definition sufficiently describes the term of Misoperation providing enough detail to be unambiguous.** **2) The drafting team believes "Unnecessary Trip - Other Than Fault" should be kept to capture Protection System Misoperations that occur during non-fault conditions. Excluding this type of Misoperation would introduce a reliability gap.** **3) The drafting team believes that the types of Misoperations that are included in the definition are sufficient. Assuming the drafting team is correcting interpreting what you are asking, an operation that occurs prior to an element setting may not be a Misoperation. If a remote Protection System operated for a Fault that should have been cleared by a local Protection System due to a coordination error at the remote terminal (set too fast), then it is an "Unnecessary Trip" at the remote location. If the coordination error was at the local terminal (set too slow), then it is a "Slow Trip" at the local location.**		
El Paso Electric	Yes	El Paso Electric Company (EPE) agrees with the definition with a slight change to the wording of the titles of "Failure to Trip - Other than Fault" and "Slow to Trip - Other than Fault". EPE believes in these applications the titles should read Failure to Operate - Other than Fault and Slow to Operate - Other than Fault. There are scenarios, in the case of a power swing, where a device or element may be set to block a trip.
Response: Thank you for your comments. **While the drafting team agrees with your logic and sentiment, we prefer to stay as close as possible to the legacy language used by the IEEE and several Regional Entities. The slight change could confuse many in the industry into thinking that new**		

Organization	Yes or No	Question 1 Comment
Misoperation types are being created.		
ACES Power Marketing Standards Collaborators	Yes	The definition and its rationale seem reasonable. One observation is to shorten the language of each category of Misoperations. Generally, detailed definitions cause more problems in compliance than short and concise definitions. We had one question for the SDT regarding the definition - is breaker failure considered a Misoperation?
Response: Thank you for your comments. **The drafting team believes the existing definition sufficiently describes the term of Misoperation providing enough detail to be unambiguous and preventing interpretations due to lack of detail. The breaker excluding its trip coils is not part of a Protection System; so, if the breaker itself physically fails to interrupt current, that failure by itself is not a Misoperation. However, if breaker failure protection falsely operates unnecessarily tripping adjacent breakers, then this false operation is a Misoperation (either category 5 or 6 depending whether a Fault existed at the time).**		
Bonneville Power Administration	Yes	BPA thanks the drafting team for their efforts as this standard has improved significantly over the previous version. While BPA believes the standard is on the right track, clarification needs to be made to a few key area's listed throughout comments below. A fair number of inadvertent operations are caused by accidental jarring of a relay panel. Since the jarring might not be due to maintenance, testing, construction, or commissioning activities, it isn't clear if it should be excluded from the definition of a misoperation by item 6. BPA suggests adding "accidental jarring" to the exclusions in item 6.
Response: Thank you for your comment. **Inadvertent operations that occur due to on-site activity are included. However, the term "accidental jarring" is too non-specific. The drafting team added "inspection" to the list of activities in category 6.**		
Western Area Power Administration	Yes	The Applications Guidelines section of the proposed standard is invaluable in clarifying the requirements. We propose that some of this information

Organization	Yes or No	Question 1 Comment
		be directly added to the associated standards. This includes statements in items (2) and (6).
Response: Thank you for your comment. **The Guidelines and Technical Basis section provides specific examples to further clarify the definition and standard. The drafting team believes the existing definition sufficiently describes the term of Misoperation providing enough detail to be unambiguous and preventing interpretations due to lack of detail. The drafting team believes the Guidelines and Technical Basis section is the proper location to document drafting team intent.**		
Utility System Efficiencies, Inc.	Yes	This standard revision is solid and specific, and should be MUCH more straightforward to audit/enforce, since it specifically requires the analysis of all operations. A comment is needed concerning the lack of any exceptions to the analysis of operations that are caused by unusual weather events. Large scale high wind events, extreme seismic events, hurricanes, tornadoes, ice storms, etc. can cause huge numbers of protection system operations of BES facilities. Many of these operations are momentary in nature and are caused by debris, out-of-right-of-way vegetation, and other line situations that are beyond established design limits for the lines and structures. Even the sustained outages may have been the result of a number of different causes, and a solid determination of the correctness of the operation may be impractical. The result of not having an exception for unusual conditions is that Transmission Owners would be spending protection personnel resources on non-productive documentation and processes, and not on maintaining and improving the reliability of the BES.
Response: Thank you for your comments. **All protection operations need to be reviewed. If a Misoperation is suspected, it must be investigated. Misoperations can be revealed at any time and are most likely to manifest themselves during system events. Therefore, it would not be prudent to simply ignore operations that occurred during large storms. As pointed out in the Guidelines and Technical Basis section, in the event of a natural disaster, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15,**		

Organization	Yes or No	Question 1 Comment
2008 provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard. This guideline allows the entity to be afforded more time for unusual events.		
Idaho Power Co.	Yes	We believe the previous comment period has produced a thorough definition of a Misoperation.
Response: Thank you for your comment and support.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP believes that the modification is an improvement over the previous draft. However, we still would like to see a commitment from the ERO-Reliability Assessment and Performance Analysis (RAPA) Group that they will align their definition when PRC-004-3 takes effect. Although the differences are minor, a difference in the criteria may require the industry to make two separate determinations on whether a relay-related event should be identified as a Misoperation.
Response: Thank you for your comment. **The present Quarterly Misoperation Reporting Form is in a state of change as the NERC SPCS attempts to provide proper data for ALR4-1 metrics and PRC-004-3 requirements. Some changes cannot be made on the reporting form until the standard is formally approved. Until then, the drafting team will forward industry comments to the NERC SPCS so that the categories of the Misoperation definition included in Quarterly Misoperation Reporting Form agree with the definition of Misoperation included in the approved Reliability Standard PRC-004-3.**		
Exelon Corp.	Yes	1) Exelon would like to see stronger wording to very clearly state that the protection system is to be evaluated as a composite system (primary and backup are part of a single composite system). 2) Under the Misoperation definition section:a. Item 1 Failure to Trip - During Fault ... change “for an Element” to “for the Element”. 3) b. Item 2 Failure to Trip - Other Than Fault ... change “for an Element” to “for the Element”.

Organization	Yes or No	Question 1 Comment
		4) c. Item 6 "Unnecessary Trip - Other Than Fault" - needs more clarification as to whether or not this includes personnel error (e.g. open test switches inadvertently).
Response: Thank you for your comments. 1) **The drafting team changed the introductory sentence of the definition to the following based on comments and should address the multiple schemes issue that you brought up: "The failure of an Element's composite Protection System to operate as intended."** 2) **The drafting team agrees and believes the suggested change adds clarity, the definition was changed.** 3) **The drafting team agrees and believes the suggested change adds clarity, the definition was changed.** 4) **The drafting team believes the language "unrelated to on-site maintenance, testing, inspection, construction or commissioning activities" clearly indicates that "personnel error (e.g. open test switches inadvertently)" is excluded from consideration as a Misoperation as long as it is related to on-site activities. Once the equipment has been returned or released to service, or the inspection has been completed, it would be considered a Misoperation regardless of the presence of the technical personnel.**		
Independent Electricity System Operator	Yes	We agree with the definition intent to provided a distinction between protection systems intended to isolate faulted elements and protection systems intented to operate for other system conditions. For the latter category, we are concerned that listing the possible causes for the "other than fault" conditions may be interpreted as the only ones to watch for. Therefore we suggest that the definition should clarify that these possible conditions are not limited to those listed in the definition
Response: Thank you for your comments. **The drafting team believes that the words "such as" before the causes are adequate to indicate that these do not purport to be an all-inclusive list.**		
Orange and Rockland Utilities	Yes	

Organization	Yes or No	Question 1 Comment
Public Service Company of New Mexico	Yes	
The United Illuminating Company	Yes	
Modesto Irrigation District	Yes	
US Bureau of Reclamation	Yes	
PSEG	Yes	
Los Angeles Department of Water and Power	Yes	
Sacramento Municipal Utility District	Yes	
NextEra Energy Inc.	Yes	
Oncor Electric Delivery	Yes	
Kansas City Power & Light	Yes	
GTC	Yes	
ISO/RTO Standards Review Committee	Yes	
Southwest Power Pool Regional Entity	Yes	
Operational Compliance	Yes	
TVA Transmission Operations and Maintenance	Yes	

Organization	Yes or No	Question 1 Comment
PacifiCorp	Yes	
Okanogan PUD	Yes	
National Grid	Yes	
seattle city light	Yes	
Wisconsin Electric	Yes	
NorthWestern Energy	Yes	
Clark Public Utilities	Yes	
American Electric Power	Yes	
Portland General Electric Company	Yes	
LCRA Transmission Services Corporation	Yes	
New York Power Authority	Yes	
Colorado Springs Utilities	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
Project 2010-05.1	Yes	
Northeast Power Coordinating Council	Yes	

Organization	Yes or No	Question 1 Comment
Associated Electric Cooperative Inc - JRO00088	Yes	
SERC Protection and Control Subcommittee (PCS)	Yes	

2. **Requirement R1 requires the responsible entities to identify and review each Protection System operation that operates the entity's interrupting device, and designate each Misoperation. Do you agree with this approach? If you do not agree, please provide specific alternatives.**

Summary Consideration:

Several commenters asked to exclude major weather events and other unusual conditions from consideration as it may not be possible to analyze operations to determine Misoperations in the given timeframes. The drafting team explained that it would not be prudent to simply ignore operations that occurred during large storms. Further, the Sanction Guidelines of the North American Electric Reliability Corporation allows the entity to be afforded more time for unusual events.

Many commenters noted confusion in the requirements in Requirement R1 surrounding accountabilities of the Protection System owner and the owner of the interrupting device. The drafting team revised Requirement R1 to provide clarity in situations where the Protection System owner is also the interrupting device owner and in situations where there are multiple owners of Protection System components of a Protection System involved in a Misoperation.

Several commenters did not understand what the phrase "designate each Misoperation" was intended to mean. The drafting team replaced "designate each Misoperation" with "determine if it (the operation) was a correct operation or a Misoperation" in Requirement R1.

Several commenters expressed concern that BES interrupting device trips resulting from control actions, especially when that function found in a protection relay, is not explicitly excluded from PRC-004-3. Although this was noted in the Guidelines and Technical Basis of the draft standard and excluded in the Facilities section of the original posting, the drafting team revised Section 4.2.4 of the Facilities section of the standard to say "Non-protective functions that may be imbedded within a Protection System are excluded". The drafting team originally listed example functions but did not want to give the impression this list was all inclusive. Further clarity on this subject remains in the Guidelines and Technical Basis.

Several commenters questioned the reasoning in Requirement R1 on why all Protection System operations need to be reviewed and found the requirement to be unnecessarily onerous. The drafting team declined to make the recommended change to because reviews of all Protection System operations are important to ensure all portions of the protection scheme are functioning as intended and to confirm that the operation was correct.

A few commenters questioned what constituted a Protection System "review" of operations of interrupting devices. The drafting team is not being prescriptive about what a Protection System operation review entails. It is left to the entity to determine what method is used to perform and document the review for the purpose of classifying an operation as normal operation or Misoperation.

A few commenters expressed concern about the 120 day timeframe to review Protection System operations. The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. This 120 day time frame takes into account the seasonal nature of Protection System operations as well as outage constraints for investigative purposes. If the investigation doesn't reveal a cause within this timeframe, the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.

A few commenters noted that the focus of PRC-004-3 should be on a standard that emphasizes internal controls over an entity's process rather than actual work execution. The drafting team declined to make this change and believes the current approach meets the reliability objectives established in the SAR for this project.

Several commenters had concerns that the standard implied additional monitoring equipment must be installed. The drafting team responded with the following: The standard does not require any additional monitoring equipment to be installed. Each responsible entity must review each of its Protection System operations and determine whether the operation should be categorized as a Misoperation based on its available information. The entity will use whatever means at their disposal in order to determine whether the operation was correct or not which may include available Disturbance Monitoring Equipment.

A few commenters thought the Protection System owner should be accountable for reviewing the Protection System operation. The drafting team did make changes to R1 to reflect the intent that the owner of the BES interrupting device would be in the best position to initiate the investigation of that operation. If it was determined that another entity's Protection System component appeared to cause the Misoperation then the burden shifts to the owner of that component. R1 was re-written to ensure this was clear.

One commenter was concerned that an entity can transmit information regarding a Misoperation but cannot force a response from the entity they sent the information to. The drafting team agreed and re-worded Measure M1 to read "Acceptable evidence for the notification required by Requirement R1, Part 1.1 may include, but is not limited to, emails, electronic files, or hard copy records demonstrating transmittal of information."

One commenter expressed concern about being able to prove it identified all BES Protection System operations. As indicated in Measure M1, an entity may use any number of means to prove it has logged interrupting device operations and the drafting team believes most entities are already saving this information.

One commenter requested clarity be provided in the rationale box for Requirement R1, that the interrupting device owner is responsible for initiating an investigation. The drafting team added the following statement to the rationale box for Requirement R1: "Requirement R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection System."

A few commenters asked whether a single CAP or action plan can address multiple similar Misoperations. The drafting team believes that a single CAP or action plan can address multiple similar events.

One commenter requested that Requirement R1 be clarified by adding "unplanned" to "Within 120 days of an interrupting device operation. The drafting team pointed out that this exception is provided in the definition of Misoperations and is also referenced in the Guidelines and Technical Basis section for category 6 of the Misoperations definition. It states: "Finally, an example of an operation that is not a Misoperation under this category is an unintended operation as a result of on-site maintenance, testing, inspection, construction or commissioning."

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	1. Requirement R1 (as well as the other Requirements in the Standard) should be formatted to start with "Each...". For consistency with the preferred format of all NERC Standards, a Requirement should start with the responsible entities, followed by under under what conditions, and then what they have to do. 2. The use of the words "in its Facility" should be changed to reflect what is being protected. Suggested wording for consideration:R1. Each Transmission Owner, Generator Owner, and Distribution Provider within 120 calendar days of a Protection System Misoperation initiating an interrupting device operation in its system shall have and implement a procedure to identify and address all Protection System Misoperations within its system. 3. Closure is also needed in the procedure to ensure a definitive corrective response to a misoperation to prevent its recurrence.
Response: Thank you for your comments. **1. The drafting team made the suggested change.** **2. The term Facility is a defined term in the NERC Glossary of Terms and captures the intent of the drafting team.** **3. The closure is covered by Requirements R2 and R4 with the development and implementation of the CAP.**		
Western Small Entity Comment Group	No	The comment group does not agree that every operation needs to be reviewed; only those that are clearly misoperations or are suspected to be misoperations should

Organization	Yes or No	Question 2 Comment
		need to be reviewed. Reviewing and documenting the review of proper operations provides no reliability benefit and may cause a detriment to reliability by directing resources away from where they might make a difference.
Response: Thank you for your comments. **The drafting team believes all Protection System operations must be reviewed to ensure Misoperations are identified. The drafting team further believes the review of all operations is required to ensure that all portions of the protection scheme are functioning as intended, and because Misoperations are sometimes not obvious or "clear".**		
Pepco Holdings Inc & Affiliates	No	1. The responsibility for R1 through R4 should be on the owner of the Protection System which initiated the interruption of a BES facility and not the owner of the interrupting device. The one 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 also reviewing all GO protection initiated trips because the TO owns the interrupting device. This is unreasonable. The party who owns the Protective System(s) that protect the BES facility that was interrupted should be the one responsible for reviewing those Protective System operations and for developing any appropriate corrective action plans. Because of compliance implications the standard must make a very clear division of compliance responsibilities between the parties when interconnected Protective Systems are involved. The owner of the Protective System(s) that initiated the trip of the BES facility should be the one responsible for reviewing the operation for correctness (R1). The owner of the Protective System(s) whose misoperation led to the interruption of a BES Facility should be the one responsible for identifying the cause and developing and implementing a corrective action plan (R2, R3, and R4). To make this perfectly clear we suggest re-wording

Organization	Yes or No	Question 2 Comment
		Requirements R1, R2, R3, and R4 as follows:R1. Within 120 calendar days of an operation of an interrupting device which interrupts a BES Facility that was caused by a Protective System operation, each Transmission Owner, Generator Owner, and Distribution Provider, who owns a Protective System which protects the BES Facility that was interrupted shall: ...R2. Within 60 calendar days of identifying the cause(s) of each Misoperation, the Transmission Owner, Generation Owner, or Distribution Provider, whose Protection System misoperated, shall...R3. For each misoperation without an identified cause(s), the Transmission Owner, Generation Owner, or Distribution Provider, whose Protection System misoperated, shall...R4. For each CAP or action plan, the Transmission Owner, Generation Owner, or Distribution Provider, whose Protection System misoperated, shall.... 2. What does R1.2 “Designate each misoperation” mean? Perhaps a more descriptive phrase would be “Designate which operations involve a Protective System Misoperation” OR “Identify and document each Protective System Misoperation”.
Response: Thank you for your comments. **1) The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.** **2) The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.**		
Souhwest Power Pool Reliability Standards Development Team	No	We would like some clarification on the review identified in R1. Based on the type of review that 120 days may or may not be enough time. We would request some example(s) be added in the Guidelines and technical reference that outline what is meant for the review in R1. Based on the examples the drafting team develops we can determine if the 120 days is appropriate. We also don’t agree that 120 days is enough time for those instances when major disturbances IE storms hurricanes tornadoes. This needs to be addressed in the requirement itself and would request that there be an extension that could be requested for those types of events

Organization	Yes or No	Question 2 Comment
		reported in DOE 417 and EOP 004.
Response: Thank you for your comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R2) to continue the investigation.** **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.**		
El Paso Electric	No	EPE believes more clarity is needed in this requirement as to responses required by other owners when their component may have contributed to the misoperation of the Protection System. For example, Entity A's protection system operates, however Entity B's component contributed to the misoperation. Entity A notifies Entity B of such component failure. There isn't a specified timeline, within the 120 days, requiring Entity B to notify Entity A of its information regarding such component, allowing Entity A to timely complete its analysis and report of the operation of its Protection System. Additionally, what would Entity A's response be if Entity B doesn't acknowledge their component's contribution to the misoperation?
Response: Thank you for your comments. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. The new Requirement R1 requires notification of all Protection System component owners (entity B in your example). There is no further action required by entity A in your example.**		
SERC Protection and Control Subcommittee (PCS)	No	1) What influence do the Application Guidelines have on the CEA? For example, the Application Guidelines clearly and correctly explain "...such as when a reverse power

Organization	Yes or No	Question 2 Comment
		relay is used to trip a breaker during generator shutdown, the operation of the control component or the function when not providing protection is not included in the definition of Misoperation and its operation would not be reviewed under this standard." A narrow reading of R1 without this explanation could result in either frivolous violations or an entity expending considerable resources to document that every normal shutdown of a generator is a correct operation. 2) Clarify the Rationale consistent with Technical Basis page 17, by clearly stating that "the interrupting device owner is responsible to investigate operations initiated by a Protection System." 3) Augment the Rationale by adding at the end, "...and submit Attachment 1 data to the CEA per section C.1.4 Additional Compliance Information." A fair number of Misoperations trip another entity's interrupting device (e.g. DTT). R1 correctly requires the interrupting device owner to initiate the investigation, but, once the Protection System component causing the Misoperation is identified, it becomes that Protection System owner's responsibility to report the Misoperation. Under the present PRC-004-2a, there is confusion on this distinction. 4) Change R1 1.2 to "Designate each operation as correct or a Misoperation. Group Misoperations for the same interrupting device that occur within 5 minutes for subsequent steps." IEEE 1366 defines 5 minutes as the demarcation between momentary and sustained events. Grouping multiple like kind operations into a single investigation / action plan / CAP is more efficient and avoids distorting statistics. It also improves BES availability and reliability by correctly reinforcing the appropriate use of automatic reclosing.

Response: Thank you for your comments.

1. **The Guidelines and Technical Basis section of the standard supplies the drafting team's reasoning and basis for writing the requirements. Consequently, the Guidelines and Technical Basis section provides background information for auditors and those responsible for implementing the standard. The Applicability Section 4.2.4.1 specifically excludes control operations such as reverse power relays. In addition further guidance on this is provided in the Guidelines and Technical Basis section.**

Organization	Yes or No	Question 2 Comment
The standard includes all protective functions of reverse power relays and excludes any control operations even if those functions are embedded in a protection device. 2. The SDT agrees. Wording has been changed in the rationale box for clarity. 3. The reporting obligations have been removed from the standard. 4. The drafting team revised Requirement R1. Please review the new Requirement R1. The drafting team believes that a single CAP or action plan can address multiple similar events.		
ACES Power Marketing Standards Collaborators	No	There is not a NERC glossary term for "interrupting device." The SDT should consider proposing a new glossary term to clarify what Protection System equipment is included in order to properly analyze all applicable equipment. Does the SDT intend interrupting devices to include switching equipment capable of interrupting a fault or would the team also include switching equipment capable of interrupting load? This term could include more than is intended and additional clarity is needed.
Response: Thank you for your comments. **For purposes of this standard, the drafting team intends "interrupting devices" to include circuit breakers and circuit switchers. The drafting team does not believe it is necessary to add this term to the NERC Glossary of Terms but will add this language to the Guidelines and Technical Basis section of the standard.**		
Colorado Springs Utilities	No	The way R1 currently reads, investigations would be required for planned work (e.g., full function trip testing). Language should be "Within 120 calendar days of an unplanned interrupting device operation in its Facility caused by a Protection System operation, each Transmission Owner, Generator Owner, and Distribution Provider shall:". The "unplanned" should apply to the interrupting device operation, vice Protection System operation, so that an investigation is required for misoperations during testing.
Response: Thank you for your comments. **This exception is provided in the definition of Misoperations in the standard and is also referenced in the Guidelines and Technical**		

Organization	Yes or No	Question 2 Comment
Basis section for category 6 of the Misoperations definition. It states: "Finally, an example of an operation that is not a Misoperation under this category is an unintended operation as a result of on-site maintenance, testing, construction or commissioning."		
Florida Municipal Power Agency	No	1. The standards takes a zero defect approach, especially in R1 which requires investigating every protection system operation; hence, if one protection system operation is missed, a violation occurs. FMPA is not in favor of a zero defect approach especially when most relay operations operate correctly. FMPA recommends usin g approaches similar to what the COM-003 and CIP v5 teams are considering. 2. R1 does not work well with the definition of Misoperation. In other words, in order to "(d)esignate each Misoperation" as required, the entity will need to have evidence that a fault actually existed. This can be quite difficult, especially for a protection systyem operation with a successful reclose (e.g., due to lightning strike for instance), how is an entity to prove that the fault existed? 3. In addition, measuring clearing time can be quite problematic, especially for electromechanical relays. How is an entity to gather evidence that relay operation was "slow" or not, and hence identify a misoperation due to slow operation? Does this require installation of equipment to be able to gather sequence of events evidence? It would seem to FMPA that a focus on internal controls for R1 is more appropriate to resolve some of these issues and challenges than the approach the SDT proposes.
Response: Thank you for your comments. **1. The standard is worded very specifically to ensure that the operation of an interrupting device triggers the beginning of an investigation. The entity will use whatever means at their disposal in order to determine whether the operation was correct or not which may include available Disturbance Monitoring Equipment.** **2. The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.** **3. The phrase "slower than intended" in parts 3 and 4 of the definition mean that the Protection System operated slower than**		

Organization	Yes or No	Question 2 Comment
the objective of the owner(s). 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 any additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate.		
PPL Corporation NERC Registered Affiliates	No	The overwhelming majority of investigations by Generation Owners under the requirement in PRC-004-3 to review each Protection System operation (R1) will be for reverse power trips during normal stop events. The SDT evidently meant to prevent this circumstance from posing an unwarranted burden by stating in the Application Guidelines that, "...in cases where a component of the Protection System or a function of a component within the Protection System is used for control of a generator, such as when a reverse power relay is used to trip a breaker during generator shutdown, the operation of the control component or the function when not providing protection is not included in the definition of Misoperation and its operation would not be reviewed under this standard." The line of demarcation between the protection and control functions of reverse power relays is not at all clear, however.We typically have for example a primary reverse power relay that trips the breaker 3 seconds after detection of motoring if all MS and HRH valves are indicating closed, and 27 seconds later regardless of valve position if it is not already offline, plus a backup relay that acts one minute after the start of motoring regardless of valve position. We take the 3-sec action as being a control function, while the other timers are protective in nature. What they protect is the low-pressure turbines from windage (high temperature) damage, however, not the generator. The reverse power function is consequently in the same class as a low lube oil pressure switch, and should not be in the scope of Protection Systems.PRC-004-3 as presently written though appears to require analysis of every reverse power trip that is not caused by the 3-second function described above, which may occur quite often given that valve position indicators are not high-reliability instruments. Each such investigation would involve documenting the, "sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records," for each normal stop (ref. the

Organization	Yes or No	Question 2 Comment
		"Requirement R1" section of the Application Guidelines) and determining whether or not the Protection System operation was slower than expected (ref. items 2 and 3 in the "Guidelines and Technical Basis" section).The number of such events can be extremely large, since peaking units often stop and start daily (or even several times per day) in high-demand seasons. Retrieving such data would be extremely time-consuming; since, where DME exists (our RRO's standard for PRC-002 has a minimum size threshold), GOs often do not have the centralized data collection facilities of TOs. Event analysis personnel may need to spend extreme amounts of time traveling to and from jobsites, since some peaking stations are unmanned or only minimally staffed. All this effort would result in no associated benefit regarding BES reliability. Reverse power relays are counted (inappropriately, we believe) as being part of the Protection System, but these devices do not trip in response to something having gone wrong, nor do they protect the generator. It is intended that negative current be experienced at some point as the unit unloads; and subsequent actuation of the reverse power relay is normal, expected and a mechanical (turbine) protection function. Requirement R1 and to the Application Guidelines should be modified to state that investigation of reverse power relay events is not part of the Protection System and PRC-004-3 consequently does not apply to such devices or, alternatively, is required only if the relay failed to function.
Response: Thank you for your comments. **Applicability section 4.2.4.1 specifically excludes control operations such as reverse power relays. In addition further guidance on this is provided in the Guidelines and Technical Basis section. The standard includes all protective functions of reverse power relays and excludes any control operations even if those functions are embedded in a protection device. It is incorrect to equate the reverse power protection function with a low lube oil pressure switch. The latter is excluded because it operates on a non-electrical quantity whereas the former operates on an electrical quantity. These longer delayed reverse power functions are not considered a control function and so do not come under that exclusion.**		
Bonneville Power Administration	No	BPA believes requirement R1 needs to provide more clarity about which entity is required to review a protection system operation. R1 requires TO's, GO's, and DP's

Organization	Yes or No	Question 2 Comment
		to review the protection system operation for an “interrupting device operation in its Facility”. This is not necessarily the same thing as the owner of the interrupting device, which is who the Application Guidelines places the responsibility on. The use of “Facility” seems inconsistent with the NERC definition of Facility: A set of electrical equipment that operates as a single BES Element. It is not clear what “in its Facility” means. The SDT appears to be using “Facility” in place of “substation”. The Rationale for R1 (blue box) mentions the owner of the interrupting device, but like R1, the rationale does not make it clear who is responsible for reviewing the protection system operation. It isn’t clear if the Rationale for R1 and the Application Guidelines are an official part of the standard, so while they might offer additional information, it is important that Requirement R1 can stand on its own and make it clear who is responsible to review the protection system operation. As presently written, BPA infers that this is not the case.Because the owner of the protective relays has the best access to the information that would be first reviewed, BPA believes that the owner of the protective relays should be required to initiate the review. From that initial review, the owner of the protective relays can then request information from other entities involved, if there are any, such as the owner of the communication system or the owner of the interrupting device. If there are different owners of the protective relays at the different terminals of an element, they should each initiate a review of their own protective relays.Requirements R2 and R3 are also unclear about who is responsible for fulfilling the requirement. Both of these specify the TO, GO, or DP as responsible for the requirement, but since there are often multiple TO’s, GO’s, or DP’s involved, which one is responsible? The Application Guideline for R2 specifies the protection system owner as being responsible. This information should be included in the Requirement itself, not just in the Application Guide.BPA believes that the owner(s) of the protection system component(s) that are identified as the cause of the misoperation in the review conducted per R1, should be responsible for R2. If there is no identified cause, the owner of the protective relay should be responsible for R3.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. The closure is covered by Requirements R2 and R4 with the development and implementation of the CAP.**		
GTC	No	Rationale for R1: State that the interrupting device owner is responsible to investigate operations initiated by a Protection System, to be consistent with the Technical Basis. For Misoperations that occur when one entity's system trips another entity's interrupting device (e.g. DTT). R1 correctly requires the interrupting device owner to initiate the investigation, but once the Protection System component causing the Misoperation is identified, it becomes that Protection System owner's responsibility to report the Misoperation. Under the present PRC-004-2a, there is confusion on this distinction.
Response: Thank you for your comments. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.**		
ISO/RTO Standards Review Committee	No	It is unclear on what "Designate each Misoperation" means. Designate a relay operation as a Misoperation or designate an identified Misoperation to a specific class or category. This part needs to be expanded.
Response: Thank you for your comments. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.**		
JEA	No	It does not appear to be cost effective to identify and review each PS operation. Also, as time goes on and issues are found and resolved this standard becomes even less beneficial because of the ever decreasing percentage of misoperations that should result from the standard.
Response: Thank you for your comments.		

Organization	Yes or No	Question 2 Comment
The drafting team believes that all Protection System operations must be reviewed to ensure all Misoperations are identified.		
TVA Transmission Operations and Maintenance	No	Comments: The requirement to review and document each Protection System Operation is overly burdensome to those utilities with heavy lightning exposure. TVA has approximately 400 interruptions a year due to lightning. To review, verify, and document each one of these to ensure whether or not a misoperation occurred within 120 days, especially during the spring-summer storm season and then find a cause for each misoperation can be overwhelming. For example, the April 27, 2011 storms took months of restoration before investigation of possible misoperations could begin. That particular storm caused about 20 misoperations. TVA would like to see the window of time extended to 180 days.
Response: Thank you for your comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. This 120 day time frame takes into account the seasonal nature of Protection System operations. Both the volume of Protection System operations as well as outage constraints for investigative purposes can be seasonal. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R2) to continue the investigation.** **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.**		
Southern Company	No	1. The question is missing a key component: Requirement R1 requires the responsible entities to identify and review each Protection System operation that operates the entity's interrupting device, designate each Misoperation, and investigate each misoperation and document the findings...The first two items are reasonable; however, the 120 days to 'and investigate each misoperation and document the findings...' can be problematic and creates a documentation requirement for something that is still under investigation. See Comment below

Organization	Yes or No	Question 2 Comment
		about timeframes. 2. The requirement says entities will “review each Protection System operation that operates the entity’s interrupting device...”. In R1, the requirement to “designate” is not defined. Is this a classification of each operation as a correct operation or a misoperation (as indicated by the VSL)? Or is this an annotation of each operation per Attachment 1? Or is this a declaration of which type of misoperation this is? Or other? Would a spreadsheet with each operation listed with an indication of correct or incorrect with a date noted be sufficient; or is other docuemtnation required? 3. What influence do the Application Guidelines have on the CEA? For example, the Application Guidelines clearly and correctly explain “...such as when a reverse power relay is used to trip a breaker during generator shutdown, the operation of the control component or the function when not providing protection is not included in the definition of Misoperation and its operation would not be reviewed under this standard.” A narrow reading of R1 without this explanation could result in either frivolous violations or an entity expending considerable resources to document that every normal shutdown of a generator is a correct operation. 4. In addition, under R1.1, the second requirement associated with notification of another entity should be stated as a separate subrequirement.

Response: Thank you for your comments.

1. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. This 120 day time frame takes into account the seasonal nature of Protection System operations. Both the volume of Protection System operations as well as outage constraints for investigative purposes can be seasonal. If the investigation doesn’t reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R2) to continue the investigation.**
2. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.**

Organization	Yes or No	Question 2 Comment
3. The revised Applicability section 4.2.4.1 specifically excludes control operations such as reverse power relays. In addition further guidance on this is provided in the Guidelines and Technical Basis section. The standard excludes any control operations even if those functions are embedded in a protection device. **4. The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.**		
ITC	No	Requirement R1 states that all operations need to be identified and reviewed. This requirement should clarified to exempt out-of-service equipment.
Response: Thank you for your comments. **Protection System operations which occur with the protected Element already out of service, that do not trip any in-service Elements, cannot be Misoperations.**		
Cleco Corporation	No	Please add some example(s) in the Guidelines and technical reference that outline what is meant for the review in R1. Does a review require a detailed report or could a simple check box be used for a review?
Response: Thank you for your comments. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. A review is an initial investigation to determine whether an operation is correct or a Misoperation. The drafting team is not being prescriptive as to what a review entails; both of your suggestions would suffice. It is left to the entity to determine what method is used to perform and document the review for the purpose of classifying an operation as normal operation or Misoperation.**		
Wisconsin Electric	No	1. In R1, the existing wording begins with: "Within 120 calendar days of an interrupting device operation ...". This wording does not specifically require a review in situations where an interrupting device fails to operate for a fault or abnormal condition. Perhaps the wording should be expanded to include these non-operations in the requirement as well.
Response: Thank you for your comments.		

Organization	Yes or No	Question 2 Comment
The drafting team believes that in the case where an interrupting device fails to operate for a fault or abnormal condition, in all but rare conditions a back-up protection will eventually operate an interrupting device triggering the start of an investigation. The drafting team believes these rare conditions would not affect BES reliability.		
Manitoba Hydro	No	The wording of this requirement is not clear enough for us to determine if we agree with it. Specifically, in R1.1 it is not clear how extensive the review of each Protection System operation should be. In reading the words of the Requirement versus the words in the associated Measures, the review process seems a lot less onerous in the wording of the requirements versus the wording of the measure. Perhaps adding additional wording to the requirement, listing the steps that should to be undertaken during the review, or even providing a review template would provide additional clarity and consistency. An entity cannot be found non-compliant with a measure, only a requirement, so the requirement should be clear when read on its own without the measure.
Response: Thank you for your comments **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. The drafting team is not being prescriptive about what a review entails, it can be as detailed as the entity deems necessary to indicate it has examined the operation to determine whether it was a correct operation or a Misoperation.**		
American Electric Power	No	AEP believes that PRC-001, rather than PRC-004, is the most appropriate standard to address an entity being required to notify another entity of protection system disturbances involving Misoperations or otherwise. If the drafting insists adding such requirements to PRC-004, we recommend making the following changes to R1:a) For 1.1, striking the language "If the entity suspects a Protection System component(s) owned by another entity contributed to a Misoperation, notify the owner of that Protection System component and provide any requested investigative information" so that it simply reads " Identify and review each Protection System operation." b) Inserting an additional requirement inbetween 1.2 and 1.3 that simply states "If the investigating entity determines Protection System component(s) owned by another

Organization	Yes or No	Question 2 Comment
		entity contributed to the Misoperation, the investigating entity shall notify the owner of that Protection System component(s) and provide any pertinent information.”
Response: Thank you for your comments. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. This standard addresses correcting the causes of Protection System Misoperations and in recognition of the fact that many Protection Systems contain components shared between entities, it will be necessary for those entities to cooperate in order to execute a CAP to correct Misoperations.**		
ReliabilityFirst	No	ReliabilityFirst Abstains and offers the following comments for consideration: 1. Requirement R1 and subsequent requirementsa. ReliabilityFirst believes Requirement R1 and subsequent requirements rely on the operation of an interrupting device and the identification by its owner that a Protection System operated and whether 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. 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. 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. 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. 3. Requirement R1, Part 1.1a. ReliabilityFirst believes the second sentence in Part 1.1 is a separate thought and recommends removing it and creating a new Part 1.2. ReliabilityFirst recommends the following for consideration for the new Part 1.2: “Notify the owner of that Protection System component and provide any

Organization	Yes or No	Question 2 Comment
		requested investigative information if the entity suspects a Protection System component(s) owned by another entity contributed to a Misoperation.”
Response: Thank you for your comments. 1. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.** 2. **The drafting team believes that in the case where an interrupting device fails to operate for a fault or abnormal condition, in all but rare conditions a back-up protection will eventually operate an interrupting device triggering the start of an investigation. The drafting team believes these rare conditions would not affect BES reliability.** 3. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.**		
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP sees this requirement as specifying “how” to identify a Misoperation, not “what” comprises a Misoperation. Although, we understand that a robust process would include a prefunctory review of every relay operation, the need to capture and document each one in a manner satisfactory to an auditor adds no reliability benefit in our view. In fact, the vast majority of relay operations are NOT Misoperations and have a well-understood cause that is known immediately (e.g.; equipment fault). Based upon this thinking, PRC-004-3 R1 should only require an event be captured that is (a) known to be a Misoperation at the time of the relay action, or (b) the cause remains unknown an hour afterwards. This should greatly reduce the number of incidents that need to be recorded - and allows focus on those which do not have a simple resolution.
Response: Thank you for your comments. **The drafting team believes that all Protection System operations must be reviewed to ensure all Misoperations are identified. The drafting team is not being prescriptive about what a review entails, it can be as detailed as the entity deems necessary to indicate it has examined the operation to determine whether it was a correct operation or a Misoperation.**		
Dairyland Power Cooperative	No	Additional clarification should be provided regarding the statement in R1.1 to “identify and review each Protection System operation”. As currently written, it is

Organization	Yes or No	Question 2 Comment
		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?
Response: Thank you for your comments **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. An event continues through the last automatic reclosing shot initiated by the composite Protection System(s). Therefore, if a Protection System Misoperated multiple times during a system event, then it is only counted as one Misoperation. The drafting team believes that a single CAP or action plan can address multiple similar events in the event of a Misoperation however each operation must be reviewed to determine whether it was correct.**		
MISO	No	It is unclear on what “Designate each Misoperation” means. Designate a relay operation as a Misoperation or designate an identified Misoperation to a specific class or category. This part needs to be expanded.
Response: Thank you for your comment. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.**		
Texas Reliability Entity	No	(1) It is not clear who is responsible for compliance with R1. Who must “identify and review”, “designate” and “investigate”? Is it the owner of the interrupting device that operated, or is it the owner of a component that caused or contributed to the Misoperation? This will be difficult to enforce without clearly assigning responsibility.(2) The requirement and the VSL assume that there are two steps in identifying a Misoperation: “determining” that an operation is a Misoperation, and then “designating” the operation as a Misoperation. There is no requirement that an entity diligently and correctly “determine” that a Misoperation occurred during its review of an operation, and there is no VSL that applies when an entity incorrectly fails to “determine” that a Misoperation occurred.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. **1. The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.** **2. It is implicit in Requirement R1 that each entity must analyze each operation and exercise due diligence to determine whether a Misoperation has occurred. The drafting team revised Requirement R1, the new Requirement R1 now states: "…determine if it was a correct operation or a Misoperation."**		
PSEG	No	We have divided R1 into two requirements (R1 and R2) below to clarify what occurs when a Misoperation occurs on a Protection System component owned by one entity and that Misoperation causes another entity's interrupting device to operate. Under the new R1 below, the interrupting device owner must first determine, within 90 days, if a Misoperation occurred and whose Protection System component was responsible. If another entity is responsible, that entity is notified. Under R2, the entity whose Protection System component misoperated must do the completed a Misoperation analysis within 210 days of when the Misoperation was identified. See below: R1. Within 90 calendar days of an interrupting device operation in its Facility, each Transmission Owner, Generator Owner, and Distribution Provider shall determine if its Protection System (a) operated properly, or (b) had a Misoperation, or (c) operated properly with indications that Protection System component(s) owned by another entity had a Protection System malfunction that caused the interrupting device operation and, if applicable, shall complete part 1.1. [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning] o If condition (b) is the findings, the interrupting device owner shall be responsible for the investigation in Requirement R2.o If condition (c) is the findings, the other Protection System owner shall be responsible for the investigation in Requirement R2.1.1 For a condition (c) finding, the interrupting device owner shall notify the owner of that Protection System component(s) and provide any available investigative information that is requested by that owner in writing. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning.]o In the event that the owner of the interrupting device and the owner of the other

Organization	Yes or No	Question 2 Comment
		Protection System component(s) disagree on the interrupting device owner's determination in R1, the Regional Entity shall investigate and make a determination as to which entity is responsible for the investigation in Requirement R2, and the identification of a Misoperation will be considered completed when Regional Entity's decision is rendered.M1. For R1, each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence of the date of the interruption device operation and the date it completed its review of each interrupting device operation, including its associated determinations. Evidence for Part 1.1 includes documentation of written transmittals to the other Protection System owner (notifications and requested information) including, but not limited to, transmittal e-mails, log entries, or letters.R2. Within 210 calendar days after identifying a Misoperation per R1, the responsible Transmission Owner, Generator Owner, and Distribution Provider shall complete an investigation report of each Misoperation that state the Misoperation category and cause. If no cause is determined, the report shall state that. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning]M2. Acceptable evidence for Requirement R2 may include, but is not limited to, a copy of a dated investigation report with documented findings for each Misoperation, including a description of the equipment involved in the Misoperation.
Response: Thank you for your comments. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. The drafting team believes it would be cumbersome to create 2 requirements for this step and disagrees with the suggested timelines. Please see the rationale boxes and the Guidelines and Technical Basis section of the standard for the drafting team's thoughts on timelines.**		
Liberty Electric Power LLC	No	See comments in Q1.In addition, the standard needs to specifically exclude reverse power relay activations from misoperations analysis, as these activations are a normal event in the shutdown of many units.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. **Section 4.2.4.1 specifically excludes non-protective relay functions (such as control functions associated with reverse power relays) that may be imbedded within a Protection System. In addition further guidance on this is provided in the Guidelines and Technical Basis section.**		
City of Jacksonville Beach, FL dba/ Beaches Energy Services	No	1.The standards takes a zero defect approach, especially in R1 which requires investigating every protection system operation; hence, if one protection system operation is missed, a violation occurs. We are, not in favor of a zero defect approach, especially when most relay operations operate correctly. We recommend using approaches similar to what the COM-003 and CIP v5 teams are considering. 2.R1 does not work well with the definition of Misoperation. In other words, in order to "(d)esignate each Misoperation" as required, the entity will need to have evidence that a fault actually existed. This can be quite difficult, especially for a protection system operation with a successful reclose (e.g., due to lightning strike for instance), how is an entity to prove that the fault existed? 3.In addition, measuring clearing time can be quite problematic, especially for electromechanical relays. How is an entity to gather evidence that relay operation was "slow" or not, and hence identify a misoperation due to slow operation? Does this require installation of equipment to be able to gather sequence of events evidence?It would seem to us that a focus on internal controls for R1 is more appropriate to resolve some of these issues and challenges than the approach the SDT proposes.
Response: Thank you for your comments. **1. The drafting team revised the standard to include the approach you suggest above.** **2. The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. The entity will use whatever means at their disposal in order to determine whether the operation was correct or not which may include available DISTURBANCE MONITORING EQUIPMENT.**		

Organization	Yes or No	Question 2 Comment
3. **The phrase "slower than intended" in parts 3 and 4 of the definition mean that the Protection System operated slower than the objective of the owner(s). 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 any additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate.**		
Independent Electricity System Operator	No	It is unclear on what "Designate each Misoperation" in R1.2 means. If could mean identitying that it was indeed a case of protection system misoperation, or designate a relay operation as a Misoperation or designate an identified Misoperation to a specific class or category. This part needs to be expanded.
Response: Thank you for your comment. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.**		
Sacramento Municipal Utility District	No	We agree Misoperations should be identified and their causes corrected. However, it is an administrative burden requiring entities to keep lists of ALL operations to prove compliance that EVERY operation was reviewed. It is strongly encouraged to model compliance requirements after the Internal Controls model currently be implemented in other standard projects rather than creating requirements that subject an entity to be in violation for missing documentation of a single review.
Response: Thank you for your comment. **The drafting team believes the current approach meets the reliability objectives established in the SAR for this project.**		
City of Tallahassee	No	1.2 requires we 'Designate each Misoperation'. I disagree with this requirement as it is inherent with the investigation that a SME will designate without it being a requirement and the need to track it.
Response: Thank you for your comment. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.**		

Organization	Yes or No	Question 2 Comment
Requirement R1.2 is written specifically to ensure each Protection System operation is reviewed to identify a Misoperation. The point of the standard is to identify and correct Misoperations and this is the first necessary step to accomplish that goal.		
Indiana Municipal Power Agency	No	1. This standard is for identifying and correcting Protection System misoperations. By requiring the identifying and reviewing of all interurupting device operations caused by a Protection System operation and then having the enity be found non-compliant to a requirement within this standard for not doing these actions, the SDT has made this an interrupting device operation tracking standard along with identifying and correcting misoperations. IMPA does not agree with this approach. 2. IMPA does support the recommendation from Florida Municipal Power Agency in using the zero defect approach.In additoin, Indiana Municipal Power Agency agrees with the additional comments submitted by Florida Municipal Power Agency (FMPA)for this question.
Response: Thank you for your comments. **1. The drafting team believes the automatic operation of the interrupting device is the most logical way to start the process of having the owner of that device analyze the Protection System operation to ensure it was correct. There is no other way to detect each Misoperation other than to analyze every Protection System operation.** **2. Please see the drafting team's responses to FMPA's comments.**		
Tampa Electric Company	No	1. The standards takes a zero defect approach, especially in R1 which requires investigating every protection system operation; hence, if one protection system operation is missed, a violation occurs. TEC is not in favor of a zero defect approach especially when most relay operations operate correctly. TEC recommends using approaches similar to what the COM-003 and CIP v5 teams are considering. 2. R1 does not work well with the definition of Misoperation. In other words, in order to "(d)esignate each Misoperation" as required, the entity will need to have evidence that a fault actually existed. This can be quite difficult, especially for a protection

Organization	Yes or No	Question 2 Comment
		systyem operation with a successful reclose (e.g., due to lightning strike for instance), how is an entity to prove that the fault existed? 3. In addition, measuring clearing time can be quite problematic, especially for electromechanical relays. How is an entity to gather evidence that relay operation was “slow” or not, and hence identify a misoperation due to slow operation? Does this require installation of equipment to be able to gather sequence of events evidence?It would seem to TEC that a focus on internal controls for R1 is more appropriate to resolve some of these issues and challenges than the approach the SDT proposes.
Response: Thank you for your comments. 1. **The drafting team believes the current approach meets the reliability objectives established in the SAR for this project.** 2. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. The entity will use whatever means at their disposal in order to determine whether the operation was correct or not which may include available Disturbance Monitoring Equipment.** 3. **The phrase “slower than intended” in parts 3 and 4 of the definition mean that the Protection System operated slower than the objective of the owner(s). 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 any additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate.**		
Essential Power, LLC	No	In R1, the requirement to “designate” is not defined.The overwhelming majority of investigations by Generation Owners under the requirement in PRC-004-3 to review each Protection System operation (R1) will be for reverse power trips during normal stop events. It is understood that the Application Guidelines specifically states that reverse power relay operations be not considered as Misoperations because the operation is a "control function" within the protective relay. But a reverse power relay is not a control device. It is a protective device. Its purpose is to protect the generator in the event the generator loses its prime mover and it begins to motor.

Organization	Yes or No	Question 2 Comment
		This form of protection is more "visible" during a normal stop event, but a reverse power relay is providing this protection at all times. It is unclear as to whether the Application Guidelines is an enforcement "tool" and guidance provided in within may be used by the CEA to determine compliance by a Generation Owners. Since it is unknown, it should be explicitly stated that reverse power trips during a normal stop event be not considered as Misoperations.It is understood that the Application Guidelines stand separate from PRC-004-3 per se, but the former document will likely be used by auditors in determining whether or not investigations were thorough enough to identify Misoperations. We therefore expect it to be obligatory, if the standard is passed in its present form, to document the, "sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records," for each normal stop (ref. the "Requirement R1" section of the Application Guidelines), including determining whether or not the Protection System operation was slower than expected ref. (items 2 and 3 in the "Guidelines and Technical Basis" section).The number of such events can be extremely large, since peaking units often stop and start daily (or even several times per day) in high-demand seasons. Retrieving such data would be extremely time-consuming; since, where DME exists (our RRO's standard for PRC-002 has a minimum size threshold), GOs often do not have the centralized data collection facilities of TOs. Event analysis personnel may need to spend extreme amounts of time traveling to and from jobsites, since some peaking stations are unmanned or only minimally staffed. All this effort would result in no associated benefit regarding BES reliability. Reverse power relays are counted (perhaps inappropriately) as being part of the Protection System, but these devices do not trip in response to something having gone wrong. It is intended that negative current be experienced at some point as the unit unloads, and subsequent actuation of the reverse power relay is normal and expected. Notes should therefore be added to R1 and to the Application Guidelines, stating that tripping of the reverse power relay during a normal stop event does not indicate a Fault, and a detailed investigation, DME downloading, speed-of-response analysis and the like are therefore required only if DME is present and if the reverse power relay failed to

Organization	Yes or No	Question 2 Comment
		function.
Response: Thank you for your comment. **Applicability section 4.2.4.1 specifically excludes control operations such as reverse power relays. In addition further guidance on this is provided in the Guidelines and Technical Basis section. The standard includes all protective functions of reverse power relays and excludes any control operations even if those functions are embedded in a protection device.**		
Oncor Electric Delivery	No	1. The proposed R1 obligates the Transmission Owner or Generation Owner to now provide notification, coordinate communication and maintain documentation follow up with neighboring entities. It appears to misalign with the NERC Event Analysis program. 2. In addition, the Regional Entities have been tasked with designing a misoperations procedure for all Registered Entities in their respective area which appears to overlap this Requirement. Oncor recommends the appropriate NERC/Regional Entity subgroups revaluate to align NERC misoperations reporting which will ensure streamlined processes for Registered Entities.
Response: Thank you for your comments. **1. The NERC Event Analysis program and this standard do not overlap. The NERC Event Analysis program is in place to provide a coordinated response to a limited number of significant events as defined in Appendix E of the ERO Event Analysis Process document. If an event occurs that would fall into one of those categories then the entity would be expected to follow the ERO Event Analysis Process.** **2. PRC-003-1 will be retired with the approval of PRC-004-3; consequently, there will be no overlap after PRC-004-3 becomes effective.**		
Kansas City Power & Light	No	R1 requires detailed investigation of every protection system operation. If operational data indicates that only the intended breakers operated for a fault on a specific protected line and a fault record from any monitoring device in the area indicates the fault was cleared in the intended time then no detailed review of the

Organization	Yes or No	Question 2 Comment
		protection system operation is required.
Response: Thank you for your comment. **Every Protection System operation must be reviewed to determine whether or not a Misoperation occurred. The standard does not specify how the review is conducted but rather depends on the due diligence of the entity to analyze the Protection System operation thoroughly enough to determine if a Misoperation occurred.**		
CenterPoint Energy		1. A misoperation can result in the tripping of multiple interrupting devices that can be owned by more than one entity. Also, the various components of a Protection System, such as current transformers, dc control wiring, and dc supply, can be owned by different entities. Instead of the owner of the interrupting devices that operate, CenterPoint Energy believes the owner of the protective relays should have the sole responsibility for reviewing interrupting device operations and reporting any Protection System misoperations. This would provide more consistent reporting and eliminate any duplicative responsibilities and efforts. CenterPoint Energy recommends establishing the applicability to the owner of the protective relays. 2. With the responsibility of reporting misoperations on protective relays they own, including those that are categorized as 'Other than Fault', the owner of the relays must review interrupting device operations whether or not they own the interrupting devices. With such a performance-based requirement, CenterPoint Energy believes it is unnecessary to establish a requirement, such as R1.1, to "Identify and review each Protection System operation". CenterPoint Energy recommends R1 maintain only the wording from R1.3, resulting in the following wording for R1: "Investigate each Misoperation (if any) and document the findings including a cause for each Misoperation, if identified."
Response: Thank you for your comments. **1. The drafting team disagrees and believes the owner of the interrupting device is in the best position to initiate the**		

Organization	Yes or No	Question 2 Comment
investigation of the Protection System operation. 2. The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. The drafting team believes every Protection System operation must be reviewed to determine whether or not a Misoperation occurred.		
Associated Electric Cooperative Inc - JRO00088	Yes	Requirement R1.1.2 Replace: “Designate each Misoperation (if any)."With: “Designate each Misoperation (if any) in order to facilitate the reporting requirements in C-1.4 .”Rationale: Add clarityConcern: While AECI believes it understands the reason for R1.1.2's "Designation" existence, we question whether it can withstand the test of time and particularly hold-up to the proposed criteria within the "NERC Paragraph 81 Project".
Response: Thank you for your comments. **The reporting obligations of C 1.4 have been removed. The focus of the standard is to identify Misoperations and subsequently establish CAPs to correct them. Requirement R1 has been revised. Please review the new Requirement R1.**		
Tacoma Power	Yes	1. The general approach and intent is supported. However, how can an entity prove that it identified all BES Protection System operations? While processes should be in place to promptly identify all BES Protection System operations, it is feared that significant cost and resources will be required to “ensure” that all BES Protection System operations are identified, which could divert staff from key reliability activities. 2. A similar concern exists for identifying all Mis-operations. Recognizing that even the proposed, revised definition of a Mis-operation could be interpreted in different ways in some cases, it is conceivable that some entities could begin over-reporting possible Mis-operations out of an abundance of caution. It should also be recognized that not all Mis-operations are of equal impact to the reliability of the BES. Over-reporting by entities to avoid even the possibility of sanctions could pose a burden on Regional Entities and NERC and might distract

Organization	Yes or No	Question 2 Comment
		the industry from correcting the key Mis-operations impacting BES reliabity.
Response: Thank you for your comments. 1. **The drafting team believes all Protection System operations must be reviewed to determine if a Misoperation occurred.** 2. **The goal of this standard is not to qualify the severity of the Misoperation but rather ensure that the cause of every Misoperation is identified and corrected as stated in the Purpose.**		
Luminant	Yes	Luminant agrees with the approach but suggests the following improvements to R1 and sub-requirements. 1) R1 should address the interrupting device as a “BES” interrupting device. 2) Luminant recommends that the concept of ownership be continued from the main requirement to each sub-requirement. For example, in 1.1, it would be written as follows: “Identify and review each of its applicable Protection System operations.”
Response: Thank you for your comments. 1. **The drafting team revised Requirement R1 to reference BES interrupting device.** 2. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.**		
Western Area Power Administration	Yes	While an entity can transmit information regarding a possible misoperation to another entity, the initiating entity cannot force a response. An entity which receives a transmittal is responsible for a response.
Response: Thank you for your comment. **The drafting team agrees with your observation. Requirement 1, Part 1.2 has been modified, Requirement 1, Part 1.2 now states that the receiving entity is required to investigate and document the findings for each Misoperation within the same 120 day period. Wording in M1 has been modified to read “Acceptable evidence for the notification required by Part 1.1 may include, but is not limited to, emails, electronic files, or hard copy records demonstrating transmittal of information.” This would ensure the entity transmitting information to another entity about a potential Misoperation provided proper notification to the owner of the**		

Organization	Yes or No	Question 2 Comment
suspected component that contributed to the Misoperation.		
Utility System Efficiencies, Inc.	Yes	The standard should recognize the need for exceptions to the analysis of operations that are caused by unusual weather events. Large scale high wind events, extreme seismic events, hurricanes, tornadoes, ice storms, etc. can cause huge numbers of protection system operations of BES facilities. Many of these operations are momentary in nature and are caused by debris, out-of-right-of-way vegetation, and other line situations that are beyond established design limits for the lines and structures. Even the sustained outages may have been the result of a number of different causes, and a solid determination of the correctness of the operation may be impractical. The result of not having an exception for unusual conditions is that Transmission Owners would be spending protection personnel resources on non-productive documentation and processes, and not on maintaining and improving the reliability of the BES.
Response: Thank you for your comment. **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.**		
Idaho Power Co.	Yes	Yes, it makes sense that the owners of the interrupting device and protection equipment should be the lead on the investigation.
Response: Thank you for your comment.		
Cogentrix Energy, LLC	Yes	The overwhelming majority of investigations by Generation Owners under the requirement in PRC-004-3 to review each Protection System operation (R1) will be for reverse power trips during normal stop events. It is understood that the Application Guidelines specifically states that reverse power relay operations be not considered

Organization	Yes or No	Question 2 Comment
		as Misoperations because the operation is a "control function" within the protective relay. But a reverse power relay is not a control device. It is a protective device. Its purpose is to protect the generator in the event the generator loses its prime mover and it begins to motor. This form of protection is more "visible" during a normal stop event, but a reverse power relay is providing this protection at all times. It is unclear as to whether the Application Guidelines is an enforcement "tool" and guidance provided in within may be used by the CEA to determine compliance by a Generation Owners. Since it is unknown, it should be explicitely stated that reverse power trips during a normal stop event be not considered as Misoperations.It is understood that the Application Guidelines stand separate from PRC-004-3 per se, but the former document will likely be used by auditors in determining whether or not investigations were thorough enough to identify Misoperations. We therefore expect it to be obligatory, if the standard is passed in its present form, to document the, “sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records,” for each normal stop (ref. the "Requirement R1" section of the Application Guidelines), including determining whether or not the Protection System operation was slower than expected ref. (items 2 and 3 in the "Guidelines and Technical Basis" section).The number of such events can be extremely large, since peaking units often stop and start daily (or even several times per day) in high-demand seasons. Retrieving such data would be extremely time-consuming; since, where DME exists (our RRO’s standard for PRC-002 has a minimum size threshold), GOs often do not have the centralized data collection facilities of TOs. Event analysis personnel may need to spend extreme amounts of time traveling to and from jobsites, since some peaking stations are unmanned or only minimally staffed. All this effort would result in no associated benefit regarding BES reliability. Reverse power relays are counted (perhaps inappropriately) as being part of the Protection System, but these devices do not trip in response to something having gone wrong. It is intended that negative current be experienced at some point as the unit unloads, and subsequent actuation of the reverse power relay is normal and expected. Notes should therefore be added to R1 and to the Application Guidelines, stating that tripping of the reverse power

Organization	Yes or No	Question 2 Comment
		relay during a normal stop event does not indicate a Fault, and a detailed investigation, DME downloading, speed-of-response analysis and the like are therefore required only if DME is present and if the reverse power relay failed to function.
Response: Thank you for your comments. **Applicability Section 4.2.4.1 specifically excludes control operations such as reverse power relays. In addition further guidance on this is provided in the Guidelines and Technical Basis section. The standard includes all protective functions of reverse power relays and excludes any control operations even if those functions are embedded in a protection device.**		
Ameren Services	Yes	(1) What influence do the Application Guidelines have on the CEA? For example, the Application Guidelines clearly and correctly explain "...such as when a reverse power relay is used to trip a breaker during generator shutdown, the operation of the control component or the function when not providing protection is not included in the definition of Misoperation and its operation would not be reviewed under this standard." A narrow interpretation of R1 without this explanation could result in either frivolous violations or an entity expending considerable resources to document that every normal shutdown of a generator is a correct operation. (2) Clarify that the rationale is consistent with the Technical Basis page 17, by clearly stating that "the interrupting device owner is responsible to investigate operations initiated by a Protection System." (3) We suggest to augment the Rationale by adding at the end, "...and submit Attachment 1 data to the CEA per section C.1.4 Additional Compliance Information." A fair number of Misoperations trip another entity's interrupting device (e.g. DTT). R1 correctly requires the interrupting device owner to initiate the investigation, but once the Protection System component causing the Misoperation is identified, it becomes that Protection System owner's responsibility to report the Misoperation. We believe that under the present PRC-004-2a, there is confusion on this distinction. (4) We suugest to change R1 1.2 to "Designate each operation as correct or a

Organization	Yes or No	Question 2 Comment
		Misoperation. Group Misoperations for the same interrupting device that occur within 5 minutes for subsequent steps.” IEEE 1366 (GUIDE FOR ELECTRIC POWER DISTRIBUTION RELIABILITY INDICES) defines 5 minutes as the demarcation between momentary and sustained events. Grouping multiple like kind operations into a single investigation / action plan / CAP is more efficient and avoids distorting statistics. It also improves BES availability and reliability by correctly reinforcing the appropriate use of automatic reclosing.
Response: Thank you for your comments. **1. The Application Guidelines and Technical Basis section of the standard supplies the drafting team’s reasoning and basis for writing the requirements. Consequently, the Guidelines and Technical Basis section provides background information for auditors and those responsible for implementing the standard. The Applicability Section 4.2.4.1 specifically excludes control operations such as reverse power relays. In addition further guidance on this is provided in the Guidelines and Technical Basis section. The standard includes all protective functions of reverse power relays and excludes any control operations even if those functions are embedded in a protection device.** **2. The wording in the Rationale box has been revised.** **3. The reporting obligations have been removed from the standard.** **4. The drafting team revised Requirement R1. Please review the new Requirement R1. The drafting team believes that a single CAP or action plan can address multiple similar events. The scenario you describe is being reviewed by various groups to determine its impact on metrics.**		
Detroit Edison	Yes	
Santee Cooper	Yes	
Dominion	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 2 Comment
Project 2010-05.1	Yes	
Southwest Power Pool Regional Entity	Yes	
Operational Compliance	Yes	
Nebraska Public Power District	Yes	
PacifiCorp	Yes	
Okanogan PUD	Yes	
National Grid	Yes	
Tri-State G&T	Yes	
NorthWestern Energy	Yes	
Clark Public Utilities	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Portland General Electric Company	Yes	
LCRA Transmission Services Corporation	Yes	
New York Power Authority	Yes	

Organization	Yes or No	Question 2 Comment
Exelon Corp.	Yes	
Orange and Rockland Utilities	Yes	
Public Service Company of New Mexico	Yes	
City of Austin dba Austin Energy	Yes	
The United Illuminating Company	Yes	
Modesto Irrigation District	Yes	
US Bureau of Reclamation	Yes	
Los Angeles Department of Water and Power	Yes	
Consumers Energy	Yes	
NextEra Energy Inc.	Yes	

3. Requirements R1, R2, and R3 introduce time limits associated with identifying, investigating, and addressing Misoperations. Do you agree with these time limits? If not, please provide specific reasons why not and alternative recommendations.

Summary Consideration:

Numerous commenters asked to clarify the time requirements under Requirement R1 when an entity cannot investigate due to extenuating circumstances and during extreme weather events. The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. This 120 day time frame takes into account the seasonal nature of Protection System operations. Both the volume of Protection System operations as well as outage constraints for investigative purposes can be seasonal. If the investigation doesn't reveal a cause within this timeframe, the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.

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.

Several commenters asked the drafting team to combine all or parts of Requirements R1, R2 and R3 into one requirement with one timeframe. The drafting team believes an overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Guidelines and Technical Basis section of the standard has been revised to add clarity for the independent 120 and 60 day timeframes.

Some commenters noted that the focus of the standard should be on requirements that emphasize internal controls over an entity's process rather than actual work execution. The drafting team believes the current approach meets the reliability objectives established in the SAR for this project.

A few commenters requested the drafting team eliminate the "procurement of funds" wording in the Requirement R1 Rationale as capital budget cycles can expand through multiple calendar years. The drafting team agreed and revised the Requirement R2 Rationale to remove the "procurement of funds" reference.

A number of commenters suggested the quarterly reporting through the Regional Entities is sufficient for addressing the time requirements for handling Misoperations. The drafting team disagreed and responded with the following: "The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion."

Numerous commenters were confused about which entity was responsible for what actions when multiple owners were involved in an operation. The drafting team revised Requirement R1 to clarify that only the owner of a Protection System component that Misoperated is responsible for documenting the findings, and developing a CAP or action plan.

Numerous commenters proposed various changes to the time requirements in Requirements R1, R2 and R3. The drafting team appreciates the suggested revisions to the standard but believes that the time requirements are appropriate. No changes were made to the draft standard.

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	1. As with R1, Requirements R2 and R3 should be formatted to start with "Each...". For consistency with the preferred format of all NERC Standards, a Requirement should start with the responsible entities, followed by under under what conditions, and then what they have to do. 2. The time limits specified are excessive for plans that do not include correcting the problem. Correction of Misoperations is extremely important to reliability because the Misoperation may indicate a defect that could have significant consequences. The time limit for R1 should be 15 calendar days, an additional 15 calendar days for R2, and 15 days for R3. 3. A definite completion time period for correcting the Misoperation should also be specified. Sixty days would not be an excessive time assuming outages may be needed, hardware ordered, etc. to prevent a recurrence.

Response: Thank you for your comments.

1. **The drafting team believes made the suggested changes.**
2. **The drafting team believes the timeframes are reasonable considering the variety of possible system events, coordinating response crews and allocating resources, etc.**
3. **The timeframe for completing the CAP cannot be prescribed in a standard due to external factors such as outage restrictions, availability of parts, capital allocation and other circumstances that can cause a CAP to be delayed. The drafting team believes entities can reliably manage and assure CAP completions.**

Organization	Yes or No	Question 3 Comment
Souhwest Power Pool Reliability Standards Development Team	No	1. See above comment. 2. For those Major disturbances there needs to be a mechanism for extending the time frames without being penalized. 3. Additionally 60 days might not be enough time to procure funds for the CAP. 4. We are OK with the time requirement on R3.
Response: Thank you for your comments. **1. Please see the response to your comment on Question 2.** **2. The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. This 120 day time frame takes into account the seasonal nature of Protection System operations. Both the volume of Protection System operations as well as outage constraints for investigative purposes can be seasonal. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation. 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.** **3. The drafting team revised the Requirement R2 rationale based upon yours and other comments. The "procurement of funds" reference has been eliminated in the Requirement R2 rationale as it is not necessarily pertinent to the requirement.** **4. Thank you for the approval.**		
El Paso Electric	No	See EPE's comment in Question 2.
Response: Thank you for the comments. **Please see the response to EPE's comment in Question 2.**		
Santee Cooper	No	We agree with the need for NERC and the regions to review the timeliness of the

Organization	Yes or No	Question 3 Comment
		analysis of misoperations. However, the regional entities, based on the RAPA template for reporting misoperations and the quarterly reporting of these misoperations, already are getting dates from the entities for the date of the misoperation, the date the corrective action was completed or, if not complete, the expected completion date. Without any additional administrative manpower commitments, the regions can already assess through the spreadsheet how long each misoperation took to completion and question anywhere timeliness seems to be a factor. They can even assess the timeliness of the original analysis of the operation (and identification of any misoperations) by checking when a new misoperation is reported against the reporting period it should have occurred in. Therefore, it seems counterproductive to prescribe timelines per misoperation, that will mean that entities have new much larger administrative burdens put on their technical staff just to document that each analysis of each operation and misoperation meet the number of days allowed. There could still be a maximum limit of what is allowed time-wise without having all of the individual date requirements. For example, additional documentation could be tied to, say, if the corrective action is not complete after the 2nd quarter that the misoperation was submitted to the regional entity. This will allow the finer detail focus of both the individual companies and the regions to be the more complicated and longer timeframe misoperations, while still supplying data (but not more than is needed to find and correct the misoperation) about the other misoperations that occur.
Response: Thank you for the comments. **The drafting team disagrees. The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion.**		
Dominion	No	1. R1 introduces a 120 day requirement in order for a correct and consistent review, and classification of, Misoperations. By introducing individual time requirements, this places unnecessary burden on entities to track dates associated with each phase of a Misoperation investigation and review. Dominion recommends an

Organization	Yes or No	Question 3 Comment
		approach similar to that recently taken in COM 003, through the development of a requirement to have a process and plan in place to address Misoperations according to regional entity guidance and oversight. Many entities currently respond to misoperations in a timely manner and adding additional tracking and time requirements does not place the priority on addressing reliability, it places the focus on data collection and date recording. 2. In the event the SDT cannot accept Regional Entity oversight, then an overall time limit should be stipulated versus the current language in the standard that includes 120 and 60 day requirements. Suggest using a 180 day overall time from the Misoperation date to finish one of these: 1)develop CAP, or 2)develop action plan or 3)develop declaration. Changes to the quarterly reporting template to remove and rename date fields will be needed and are included under question 5 comments. 3. Revisions should be made to the Misoperations reporting template to capture requirements not currently covered in the template. For example, R2 introduces the option of a “declaration”. The template should include a feature to record a declaration. Entities should not be required to use multiple tracking tools or techniques to document the various requirements. One tool should exist to do this and currently all entities use the reporting template. 4. All references to an investigation report should be changed to read “Misoperation investigation report” or “investigation report due to misoperations”. Without this change it could be interpreted that all operations require an investigation report. 5. R3 introduces an undefined term - an “action plan” for those misoperations without an identified cause. There is a concern that entities will be confused with Corrective Action Plan and action plan terminology. Suggest changing R3 to read “For each Misoperation without an identified, the Registered Entity cause(s), the Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of the Misoperation, identify any additional investigative actions

Organization	Yes or No	Question 3 Comment
		and/or Protection System modifications., including a work timetable, or document why no further investigation or actions will be taken.

Response: Thank you for the comments.

1. **The drafting team believes the current approach meets the reliability objectives established in the SAR for this project. The drafting team believes the timeframes are sufficient and necessary and they will remain in the new standard.**
2. **An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Technical Guidelines area has been revised to add clarity for the independent 120 and 60 day timeframes.**
3. **The NERC System Protection and Control Subcommittee (SPCS) is the group responsible for the Misoperations reporting template. The drafting team is forwarding all comments to the SPCS for consideration.**
4. **The drafting team agrees and added "Misoperation" to "investigation report" for clarity.**
5. **The term 'action plan' was utilized to allow for references within the standard for the activities that occur within Requirement R3 including references in Measures M3 and M4 as-well-as Requirement R4. While the term is not defined in the NERC Glossary, the drafting team believes there is sufficient clarity for use within the standard and modified the rationale box and the Guidelines and Technical Basis section of the standard.**

Organization	Yes or No	Question 3 Comment
Luminant	No	The time frames and activities in R1-R3 are confusing and can be simplified. Luminant suggests that R1, 2, 3 be revised to allow owners 180 days from the time of the BES interrupting device operation to investigate, determine the cause, and develop a CAP (cause known) or action plan (cause unknown). An action plan can result in identifying a cause and should include a CAP. If a cause cannot be determined, the investigation is closed. Below is our recommendation for R1-R3: R1. Within 180 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, the applicable Transmission Owner, Generator

Organization	Yes or No	Question 3 Comment
		Owner, and Distribution provider shall: [Violation Risk factor: Medium}{Time Horizon: Operations Assessment, Operations Planning]1.1 Identify and review each of its applicable Protection System operations. 1.2 For its Protection System operations that are interdependent with the Protection Systems of another owner, the entity shall notify the owner of the interdependent Protection System.1.3 Identify each of its Protection System misoperations, determine a cause (if known), and develop a Corrective Action Plan (CAP).R2. For misoperations where the cause cannot be determined within 180 days of the BES interrupting device operation, the applicable Transmission Owner, Generator Owner, and Distribution Provider shall develop an action plan to: [Violation Risk factor: Medium}{Time Horizon: Operations Assessment, Operations Planning]o Develop a CAP within 60 days after identifying the cause of the misoperation for the Protection System component(s).o Where applicable, explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability and close the investigation.R3. Each Transmission Owner, Generator Owner, or Distribution Provider shall implement its CAP according to the established timetable. [Violation Risk factor: Medium}{Time Horizon: Operations Assessment, Operations Planning].
Response: Thank you for the comments. **An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Guidelines and Technical Basis section has been revised to add clarity for the independent 120 and 60 day timeframes.**		
SERC Protection and Control Subcommittee (PCS)	No	1. SERC objects to the timetables and the compliance burden it places on entities: There is no evidence or indication that entities are not doing due diligence in reviewing operations. Quarterly reporting schedules help drives closure. 2. R1 correctly requires the interrupting device owner to initiate the investigation,

Organization	Yes or No	Question 3 Comment
		but when the Protection System interconnects with another entity and there are indications that the other entity's Protection System components misoperated (i.e. Other entity sends a spurious DTT), then, once the cause of the Misoperation is determined, it should be the responsibility of the owner of the Protection System that misoperated to report; thus removing the burden of reporting from the interrupted device owner. In some cases there may be several devices interrupted which are owned by different entities and the Protection System failure resulted from an entity that had no devices that were interrupted or affected at the location where the Misoperation occurred. Under the present PRC-004-2a, there is confusion on this distinction. 3. R1 introduces a 120 day requirement for performing a correct and consistent review and classification of Misoperations. By introducing individual time requirements, this places an unnecessary burden on entities to track and document each phase of investigation and review of a Misoperation. Similar to the approach taken in COM 003 recently which included a requirement to have a process and plan to address Misoperations according to regional entity guidance and oversight. Many entities currently respond to misoperations in a timely manner and to add additional tracking and time requirements does not place the priority on addressing reliability, it places the focus on data collection and documentation. 4. In the event the SDT cannot accept Regional Entity oversight, then an overall time limit should be stipulated versus the current verbiage in the standard referencing the 120 and 60 day requirements. 5. All references to an investigation report should be changed to read "Misoperation investigation report" or "investigation report due to misoperations". Without this change it could be interpreted that all operations require an investigation report.

Response: Thank you for the comments.

1. The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response,

Organization	Yes or No	Question 3 Comment
CAP creation and completion. The drafting team believes the timetables make the requirements measurable. 2. The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. 3. The drafting team believes the current approach meets the reliability objectives established in the SAR for this project. The drafting team believes the timeframes are sufficient and necessary and they will remain in the new standard. 4. An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. 5. The drafting team agrees and added "Misoperation" to "investigation report" for clarity.		
ACES Power Marketing Standards Collaborators	No	The SDT should consider providing an exception process if there are unforeseen delays that inhibit an investigation to occur within 120 days. For instance, there could be difficulties with coordination for multiple interrupting device owners. There are numerous reasons that could cause a delay to go beyond the 120 days, so there should be some sort of time allowance to provide extra time if the excuse is justified and reasonable.
Response: Thank you for the comments. The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation. 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.		

Organization	Yes or No	Question 3 Comment
Florida Municipal Power Agency	No	FMPA believes there ought to be exceptions for an “Act of Nature”, e.g., event like a hurricane, that can result in a great many protection system operations but still require investigation of all of them within 4 months.
Response: Thank you for the comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.** **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.**		
Bonneville Power Administration	No	The time limits associated with R1, R2, and R3 are acceptable. Under the Compliance section, 1.4 requires a report to be submitted to the CEA within two calendar months following the end of each quarter. For an operation of an interrupting device at the end of a yearly quarter, the report will need to be submitted no more than 2 months after the operation. This will not allow the 120 days for review given by R1, nor the 60 days to develop the corrective action plan allowed by R2. BPA believes that the 2 month limit after the end of the yearly quarter to submit the report should be extended to agree with the 120 day limit of R1 and the 60 day limit of R2.
Response: Thank you for the comments. **The reporting obligations have been removed from the standard.**		
GTC	No	GTC does not agree to the timetables and the compliance burden it places on entities: While the intent is correct, to insure that all operations are being reviewed and misoperations are found and corrected, the quarterly reporting that we are

Organization	Yes or No	Question 3 Comment
		already doing is more than sufficient. Additionally, the NERC Standards Committee approved the draft SAR for Project 2013-02 "Paragraph 81" which identifies criteria for retiring or modifying existing Reliability Standards. The proposed time limits appear to conflict with the initial criteria identified via the P81 initiative. The dated limits would likely encourage entities to shift focus on closing out documents instead of spending the appropriate time studying the operation event to determine true root cause and development of an appropriate corrective action plan. Ultimately, the introduction of time limits would have little to no impact to the protection or reliable operation of the BES, and will likely find their way to the FFT process...and thus a future candidate for elimination via P81. GTC recommends the SDT to remove these introduced limits and refine focus to results-based to achieve the desired reliability result of analyzing operations to identify misoperations and implementing corrective actions to prevent future occurrences.
Response: Thank you for the comments. **The drafting team disagrees. The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion. Consequently, the drafting team does not believe the timelines are administrative or detract from the reliable operation of the BES; instead they add measurability to the goal of determining cause and developing appropriate corrective actions.**		
ISO/RTO Standards Review Committee	No	We agree review of each Protection System operation is important, however, there could be voluminous events from a natural event that may be burdensome on entities to provide reports within the allotted time frame. Prirorititization should be given for events that are suspected to be misoperations based on the entities' judgment.
Response: Thank you for the comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the**		

Organization	Yes or No	Question 3 Comment
investigation. **All protection operations need to be reviewed. If a Misoperation is suspected, it must be investigated. Misoperations can be revealed at any time and are most likely to manifest themselves during system events. Therefore, it would not be prudent to simply ignore operations that occurred during large storms. As pointed out in the Guidelines and Technical Basis section of the standard, in the event of a natural disaster, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard. This guideline allows the entity to be afforded more time for unusual events.**		
JEA	No	1. If outages are necessary to properly examine and test protection system components 120 days may be too short especially during storm season. We recommend this be increased to 180 days. R1 also needs exceptions for major system events and natural disasters. 2. The R2 time frame of 60 days to develop a corrective Action Plan for the components of Protection misoperations is insufficient to consider applicability to other protection systems, different options and their cost/benefit scenarios, coordinate resources, develop schedules, and procure funding. Since the clock starts ticking as soon as the cause is identified, this should be extended to 180 days. Again it seems prudent to have an exception for major system events and natural disasters. If R1 & R2 timeframes were increased as suggested above this should result in an increase in this area also since the 180 day time frame was arrived at by adding the two preceding time frames. The new resulting time frame should be 360 days.
Response: Thank you for the comments. **1. The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.**		

Organization	Yes or No	Question 3 Comment
2. All protection operations need to be reviewed. If a Misoperation is suspected, it must be investigated. Misoperations can be revealed at any time and are most likely to manifest themselves during system events. Therefore, it would not be prudent to simply ignore operations that occurred during large storms. As pointed out in the Guidelines and Technical Basis section of the standard, in the event of a natural disaster, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard. This guideline allows the entity to be afforded more time for unusual events. 3. The drafting team believes that 60 days is an appropriate timeframe for creation of a CAP including consideration of items mentioned in your comments. The completion of the CAP is determined by the timeframes identified by the entity in the CAP and should consider such things as available resources and outage schedules.		
Operational Compliance	No	Distinguishing between NERC and WECC time requirements and deciding which is "more stringent" is too confusing and time-consuming. WECC requirements should fully complement and enhance NERC requirements. The WECC quarterly reporting system already in place is essentially a good one. In a nutshell: Q1. W/in 60 days of end of Q1 - elements of PRC-004-3.R1, Q2. W/in 60 days of end of Q2 - CAP created and documented, Q3. W/in 60 days of end of Q3 - CAP in place or reason for no CAP.
Response: Thank you for the comments. **The Project 2010-05.1 drafting team has no control over the WECC standards. Regional standards must be more stringent than the Continent-wide NERC standard. The drafting team included the following in the Background section of the draft standard: “Note that the WECC Regional Reliability Standard PRC-004-WECC-1 relates to the reporting of Misoperations for a limited set of WECC Paths and Remedial Action Schemes. In those cases where PRC-004-WECC-1 overlaps with the Continent-wide standard, entities are expected to comply with the more stringent standard.” The reporting obligations have been removed from PRC-004-3.**		
TVA Transmission Operations and Maintenance	No	The time limits do not allow for equipment that is difficult to get out of service to allow testing/troubleshooting to investigate and develop a CAP. Often transmission line of transformer bank outages can only be obtained during very limited time frames or must be scheduled months in advance. Only after the investigation is complete can the final CAP be confirmed, depending on what is found during

Organization	Yes or No	Question 3 Comment
		investigative outages. The 180 days in some cases may need to be at least 270 or more for some investigations.
Response: Thank you for the comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.**		
Nebraska Public Power District	No	For R1 there is 120 days to identify, review, designate, correspond with associated etitites and investigate a misoperation to determine the cause. For R2 there is 60 days to develop a CAP once a cause is determined. This seems somewhat confusing in it may cut in to the 4 month time frame for R1. Perhaps it would be better to just state that a corrective action plan shall be developed within 6 months as in R3. This would be 6 months to create a CAP as the maximum interval or declare why a CAP is not needed. This may also be easier to audit since documenting when the cause is determined to start the time line would not be required. The VSL could then be updated and be simplified.
Response: Thank you for the comments. **An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days.**		
PacifiCorp	No	PacifiCorp is concerned that the 120-day time limit in R1 is insufficient. 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 to 90 days for each entity to complete their

Organization	Yes or No	Question 3 Comment
		respective activities in sequence. This would increase the total from 120 to 180 days under R1.
Response: Thank you for the comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.**		
Southern Company	No	1. We do not agree with the introduction of the noted timeframes. There is no indication that the extremely large percentage of entities have not been doing due diligence in analyzing operations, identifying misopertions, and taking appropriate actions to prevent reoccurrence all of which are inherent to the existing Standard. If the only reason to place these time limits is to have a basis for compliance (i.e. you can't require someone to do something unless you tell him how long he has, because he can always say 'I was going to do it tomorrow); then, the time limits should be removed. We offer two potential suggestions for improvement: 2. R1 should not be changed from the previous posting. The requirement should be that the entity has a procedure and process. Compliance can be gauged based on an entities compliance culture, oversight and review of processes and procedures. The SDT should utilize the approached introduced in their recently posted- COM-3. or 3. It is suggested that all Protection System operations for a given quarter are reviewed, analyzed, classified before the reporting due date to the RE (at the end of two calendar months following the quarter) - this will cover all of the deadlines found in requirements R1, R2, and R3. Also, we believe that any required CAP

Organization	Yes or No	Question 3 Comment
		should be developed and documented by this same date. Placing the 120 day and 60 day time frames for each Prot Sys operation unnecessarily complicates the evaluation, resolution, tracking, and documentation of each misoperation. For a large entity with many operations per quarter, the multiple time frames for R1, R2, and R3 are unecessarily overbearing. 4. Requirement R3 should be combined with Requirement R2. A CAP developed and documented as described in R2 can address resolving identified causes of misoperations as well as addressing additional investigative plans for determining a cause. Misoperations with no identified cause can be handled as described in the draft standard.
Response: Thank you for the comments. **1. The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion. The drafting team believes the timetables add measurability to the goal of determining cause and developing appropriate corrective actions.** **2. The drafting team believes the current approach meets the reliability objectives established in the SAR for this project. The drafting team believes the timeframes are sufficient and necessary and they will remain in the new standard.** **3. An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days.** **4. Requirement R3 covers cases where there are significant challenges determining the Misoperation cause(s) such as outage constraints and multiple entity coordination. The 'action plan' developed in Requirement R3 establishes the course of action and the associated work timetable. While Requirement R3 (action plan) may appear similar to the Requirement R2 (CAP), its intent is different.**		
ITC	No	R1, 120 calendar days may not be enough time for those instances when multiple

Organization	Yes or No	Question 3 Comment
		outages occur during large storms such as hurricanes, tornadoes, etc. This needs to be addressed in R1 and should allow that an extension can be requested for those types of events reported in DOE 417 and EOP 004.
Response: Thank you for the comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.** **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.**		
seattle city light	No	Seattle City Light (SCL) does not agree with the time limits. SCL agrees that it is important for reliability that Misoperation CAPs be created and implemented within a reasonable time, but does not believe that the reliability benefit that might possibility accrue from meeting staged interim deadlines for analysis and for creating a CAP outweighs the administrative compliance burden created to document that each interim deadline has been met. SCL instead recommends that a single time limit be required for implementing an appropriate CAP following each Misoperation. Furthermore, SCL recommends a somewhat longer period, of either 240 or 365 days, to accommodate seasonal constraints. For SCL, elements associated with a Misoperation occurring in October at the beginning of the winter storm season might, in a heavy winter, not be available for operational analyses and testing until the following March or April, a length of time that could exceed 180 days. Such seasonal constraints are not unique to SCL, but also exist in summer for entities in the southern parts of North America.

Organization	Yes or No	Question 3 Comment
Response: Thank you for the comments. **An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Guidelines and Technical Basis section of the standard has been revised to add clarity for the independent 120 and 60 day timeframes.** **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.** **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.**		
Cleco Corporation	No	1. For those Major disturbances there needs to be a mechanism for extending the timeframes without being penalized. 2. Additionally 60 days might not be enough time to procure funds for the CAP. 3. We are ok with the time requirement on R3.
Response: Thank you for the comments. **1. The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.** **The drafting team agrees with your comment about instances when major disturbances occur. As noted in the Guidelines and**		

Organization	Yes or No	Question 3 Comment
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. **2. The drafting team revised the R2 Rationale and removed the "procurement of funds" reference in the Requirement R2.** **3. Thank you.**		
Manitoba Hydro	No	The time limit for R2 should be changed from "60 calendar days of identifying the cause" to "180 calendar days from the misoperation". Requiring the entity to track both the date of the operation (for R1) and the date the cause was identified (R2) seems like unnecessary work. This suggestion does not change the maximum time to complete R2.
Response: Thank you for the comments. **An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Technical Guidelines area has been revised to add clarity for the independent 120 and 60 day timeframes.**		
NorthWestern Energy	No	We have a concern on R2 on the 60 calendar days to make a CAP (corrective action Plan). Making a plan with a timeline in 60 days poses an issue where budgeting is required to perform a major relay upgrade to fix a problem. We fear this wording could expose us to potential penalties for not meeting a CAP's stated time line that would be made before the budgeting approval and scheduling process is completed.
Response: Thank you for the comments. **The drafting team understands that the capital budgeting cycle for many entities can extend for many months however the drafting team believes there is sufficient latitude in the standard to revise a CAP and associated timeframes as needed by the**		

Organization	Yes or No	Question 3 Comment
entity. The entity can set the work timetable as identified in Requirement R2 and the Guidelines and Technical Basis section "Deferrals or other relevant changes to the CAP or action plan need to be documented so that the record includes not only what was planned, but what was implemented." Allowances for changes to a CAP are accounted for in the standard.		
American Electric Power	No	1. In general, AEP supports the idea of time limits in regards to R1, R2, and R3. However, though these proposed limits might be reasonable and attainable under normal operating conditions, the proposed time limits for R1 and R3 would not likely be reasonable during major distubances and significant events. The volume of analysis required in these situations is simply too great and complex to complete in the time limits proposed. Either the time limits proposed need to be extended to accommodate analysis during major distubances, or else there must be provisions for granting time extensions when major events occur. For example, if there was an event that was in scope under EOP-004 disturbance reporting, that entity could be afforded the flexibility to work out the allowed time limits with their Regional Entity. 2. In addition, an entity's allowed time window to repond should not begin until it has officially received notification.
Response: Thank you for the comments. **1. The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.** **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.** **2. The drafting team revised Requirement R1 based; please review the new Requirement R1. The notified entity has the remainder of the 120 day period per Requirement R1 to determine the cause of the Misoperation; then has at least 60 days to**		

Organization	Yes or No	Question 3 Comment
create a CAP or an action plan as stated in Requirements R2 and R3.		
ReliabilityFirst	No	ReliabilityFirst Abstains and offers the following comments for consideration:3. Requirement R2a. ReliabilityFirst believes the phrase “Within 60 calendar days of identifying the cause(s) of each Misoperation” relates to the designation of the cause of each Misoperation as identified in Requirement R1, Part 1.3 or as identified through implementation of the action plan per Requirement 4, Part 4.1? If so, ReliabilityFirst recommends add the parenthetical “(per Requirement R1, Part 1.3 or Requirement R4, Part 4.1)” to Requirement R2 in order to further clarify when the timing of the 60 calendar day window begins.
Response: Thank you for the comments. **The drafting team revised the rationale boxes for Requirements R2, R3, and R4 based on your suggestion.**		
Portland General Electric Company	No	1. Managing multiple deadlines based upon event date is difficult and does not align with quarterly reporting requirements (also see response to question 5). If more stringent deadlines are to be applied, there should be separate deadlines for identification of misoperations (less than 120 days) and identification of the cause (more than 120 days). Complex events affecting multiple workgroups or entities as well as those involving equipment failure may result in entities taking more than 120 days to determine the Root Cause. Often misoperations result in the need to send protective relays back to the manufacturer, but relay manufacturers have no requirement to meet these deadlines. Not allowing sufficient time to determine the Root Cause will result in more events being referred to R3 (no identified cause) or CAPs being developed based upon incorrect causes. 2. Complex events affecting multiple work groups or equipment failure may result in an entity taking more than 60 days to develop a CAP even after a cause is identified. Not allowing sufficient time could result in less than desirable CAPs.

Organization	Yes or No	Question 3 Comment
Response: Thank you for the comments. 1. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages or coordinating with outside entities. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.** **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.** 2. **The drafting team disagrees. The team believes that 60 days is adequate to develop and document a CAP once the cause has been identified. The completion of the CAP, including any revisions, is completely under the control of the entity.**		
LCRA Transmission Services Corporation	No	1. For the R2 time basis, the 60 day period for developing a CAP is reasonable; however, identifying the specific date the cause was identified could be subjective and could lead to an unnecessary violation due to a simple clerical error. We would recommend stating the CAP should be developed within 180 days of the interrupting device operation (the event). 2. We do not view R3 as being necessary and could even put an entity at conflict with R1 and R2 (i.e. the cause has not been determined within 120 days; however, the investigation continues and at day 140 the cause is determined and the entity is now in violation of R1) An entity should be able to complete all investigations within R1 requirements of 120 days, even if the finding is unknown. There is no benefit to extending the investigation out 180 days and beyond. Similarly, for an unknown cause a corrective action plan to plan and install controls to monitor the relay scheme to identify the cause of a repeat failure can be planned and executed within the requirements of R2 and R4.
Response: Thank you for the comments.		

Organization	Yes or No	Question 3 Comment
1. An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Guidelines and Technical Basis section of the standard has been revised to add clarity for the independent 120 and 60 day timeframes. 2. Requirement R1 does not require an entity to have a cause identified within 120 days. The standard includes Requirement R3 to address those instances where there are significant challenges to determining a Misoperation cause such as multiple entity coordination, outage constraints, availability of parts and resource allocation. The action plan developed in Requirement R3 allows the entity to set the work timetable and revise that timetable as required. Implementation of the action plan in Requirement 4, Part 4.1 will lead the entity to a cause or to a declaration that a cause cannot be determined on the entity's work timetable.		
Dairyland Power Cooperative	No	R1 requires the identification and review of an operation, as well as the designation and investigation of a Misoperation, all within 120 days whereas R2 requires the development of a corrective action plan within 60 days of identifying the cause of a Misoperation. It is a concern that these proposed timeframes will create a disincentive for early identification of Misoperations. As an example, if a Misoperation is identified on day 2 after the incident, the corrective action plan must be developed no later than day 62 following the incident. However if an entity were to delay identification of the Misoperation until day 120 after the incident, the corrective action plan would not have to be developed until day 180. To prevent deterring entities from identifying Misoperations sooner, it suggested the drafting team consider requiring the corrective action plan by day 180 regardless of when the misoperation cause was officially identified. Doing so would avoid entities having to worry about the official date of Misoperation identification.
Response: Thank you for the comments. **An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of**		

Organization	Yes or No	Question 3 Comment
the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an ‘action plan’ execution. If the cause is found via an ‘action plan’, the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Guidelines and Technical Basis section of the standard has been revised to add clarity for the independent 120 and 60 day timeframes.		
MISO	No	Comments: We agree review of each Protection System operation is important, however, there could be voluminous events from a natural event that may be burdensome on entities to providereports within the allotted time frame. Priroritization should be given for events that are suspected to be misoperations based on the entities’ judgment.
Response: Thank you for the comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages and other factors. If the investigation doesn’t reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.** **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.**		
Public Service Company of New Mexico	No	1. R1/R2: Regarding the proposed timeframes for completion of R1 and R2 as 120 days and 60 days respectively, PNMR suggests that the drafting team amend the requirements such that the combination of the two requirements not exceed 180 days, but allow for flexibility in either the analysis of the operation and/or the development of the CAP such that either one could be extended if needed but the entire timeframe allowed for both would not exceed the proposed timeframes as originally drafted.R1: PNMR proposes that an exception to the timeframe in R1 be allowed for complex failure to trip scenarios which are less frequent but can be difficult to recognize. PNMR requests that the time clock

Organization	Yes or No	Question 3 Comment
		start from the time of discovery rather than the time of the operation. The requirement would instead read: “R1. Within 120 calendar days of discovery of an interrupting device operation in its Facility caused by a Protection System operation,...” 2. Alternatively, PNMR suggests that there be an exception granted for certain failures to operate that are discovered after-the-fact.
Response: Thank you for the comments. 1. **An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an ‘action plan’ execution. If the cause is found via an ‘action plan’, the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Technical Guidelines area has been revised to add clarity for the independent 120 and 60 day timeframes.** **The standard includes Requirement R3 to address those instances where there are significant challenges to determining a Misoperation cause such as multiple entity coordination, outage constraints, availability of parts and resource allocation. The action plan developed in Requirement R3 allows the entity to set the work timetable and revise that timetable as required.** 2. **The drafting team revised the standard to eliminate the need for exceptions. Please see the revised standard.**		
City of Austin dba Austin Energy	No	Given the length of the summer season in some parts of the country, Austin Energy requests an adjustment to the time limits to sufficiently account for outage constraints for investigative purposes. AE requests that R1 allow for 180 calendar days and R3 allow for 240 calendar days. (These comments are similar to those submitted by Seattle City Light which, due to the length of the winter season in their part of the world, they also requested a longer period).
Response: Thank you for the comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and**		

Organization	Yes or No	Question 3 Comment
investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation. **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.**		
Modesto Irrigation District	No	1. Standardize a single time frame for evaluation and remidiation. Keep it simple. 2. Also recommend longer time period for completion of remidiation, such as 240 days.
Response: Thank you for the comments. **1. An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Technical Guidelines area has been revised to add clarity for the independent 120 and 60 day timeframes.** **2. The Corrective Action Plan (CAP) planned completion date is determined by the entity.**		
PSEG	No	In addition to the new R1 and R2 above, R3 through R4 below are an alternative to replace the proposed R1 through R3. R3. If the cause(s) for a Misoperation is identified in Requirement R2, the Transmission Owner, Generator Owner, and Distribution Provider shall, within 270 days of identifying a Misoperation per R1: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning] o Develop and document 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 o Explain in a declaration why

Organization	Yes or No	Question 3 Comment
		corrective actions are beyond the entity's control or would reduce BES reliability. M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R2 that must include a dated CAP or a dated declaration explaining why there is no need to develop a CAP.R4. If the cause for a Misoperation is undetermined in Requirement R2, the Transmission Owner, Generator Owner, and Distribution Provider shall, within 270 calendar days of identifying a Misoperation per R1, complete: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning] o Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including an estimated timetable, or o A declaration explaining why no further actions will be taken. M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R5 that must include a dated action plan or a dated declaration explaining why no further action will be taken.
Response: Thank you for the comments. **The drafting team appreciates your efforts and suggested revisions to the standard but declines to make the suggested changes.**		
Los Angeles Department of Water and Power	No	In regards to R2, the 60-day period for developing a CAP seems to be reasonable; however, this period starts from the date the cause of Misoperation is identified. "Date of cause" could be subjective and can potentially generate confusion and unnecessary violations. LADWP recommends using the date of "device interruption operation" and change "60 days" to "180 days."
Response: Thank you for the comments. **An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Guidelines and Technical Basis**		

Organization	Yes or No	Question 3 Comment
section of the standard has been revised to add clarity for the independent 120 and 60 day timeframes.		
City of Jacksonville Beach, FL dba/ Beaches Energy Services	No	We believe there ought to be exceptions for an "Act of Nature", e.g., event like a hurricane, that can result in a great many protection system operations but still require investigation of all of them within 4 months.
Response: Thank you for the comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.** **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.**		
Sacramento Municipal Utility District	No	We urge the Drafting Team to address the time limits and report requirements utilizing the Internal Controls Process thereby eliminating the 'zero-defect' language found in the requirements. While we agree with time limits to finalize any findings we disagree with the multiple date requirements. We believe that an internal control process should be identified by the entity that eliminates the potential for administrative errors. This would allow the entity to perform necessary actions and reporting in accordance to their policy specifically on facilities determined to be critical. Where an entity has a 'no-touch' in effect of certain facilities this method would allow them to evaluate the relays off the critical period.
Response: Thank you for the comments. **The drafting team believes the current approach meets the reliability objectives established in the SAR for this project. The drafting team believes the timeframes are sufficient and necessary and they will remain in the new standard.**		

Organization	Yes or No	Question 3 Comment
CenterPoint Energy	No	Instead of requiring a Corrective Action Plan be developed within 60 days of identifying the root cause, as provided for in R2, CenterPoint Energy recommends the timeframe be 180 days after the date of the misoperation. Requiring a Corrective Action Plan to be developed within 60 days of identifying a root cause would create a new, additional date that must be tracked. To facilitate the ease of tracking, as well as auditing, CenterPoint Energy recommends using the following for developing a Corrective Action Plan: "For each Misoperation with an identified cause, within 180 days after the date of the misoperation, the Transmission Owner, Generator Owner, or Distribution Provider shall:".
Response: Thank you for the comments. **An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Guidelines and Technical Basis section of the standard has been revised to add clarity for the independent 120 and 60 day timeframes.**		
Indiana Municipal Power Agency	No	Indiana Municipal Power Agency agrees with the comments submitted by Florida Municipal Power Agency (FMPA).
Response: Thank you for the comments. **Please see the drafting team's response to FMPA.**		
Tampa Electric Company	No	TEC believes there ought to be exceptions for an "Act of Nature", e.g., event like a hurricane, that can result in a great many protection system operations but still require investigation of all of them within 4 months.
Response: Thank you for the comments.		

Organization	Yes or No	Question 3 Comment
The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation. **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.**		
NextEra Energy Inc.	No	NextEra Energy Inc. (NextEra) disagrees that 120 days provides sufficient time to investigate all types of misoperations. For example, NextEra does not agree with the rationale that 120 days is sufficient time to account for outage constraints. This timeframe is particularly troubling in the context of nuclear power plants that generally do not schedule a switchyard outage unless it is consistent with its refueling outage - which can be as long as 18 months apart. Thus, NextEra recommends that R1.3 be revised as follows to provide a clearer process and more flexibility:1.3 Investigate each potential Misoperation and document the findings. The cause of a Misoperation may be initially listed as "Unknown/unexplainable" and the Analysis and Corrective Action Status listed as "Analysis - In Progress". The entity should continue their normal process of investigation and after a cause is determined resubmit the Misoperation to update the information.
Response: Thank you for the comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.**		
Ameren Services	No	1. We suggest that "cause(s)" be changed to "cause" in R2 to avoid time limit confusion, and be consistent with the use of "cause" throughout the rest of this

Organization	Yes or No	Question 3 Comment
		standard. 2. Although wording is clear that R2 be completed within 60 days of identifying the cause, some entities may incur violations by glibly adding the 120 days in R1 to the 60 days in R2. We suggest pointing out that the entity will have to intentionally record and track when they've identified the cause, and providing an example in the Application Guidelines for R2 on page 18 will provide better clarity. For example, if the entity identifies the cause on 3/31 for a 3/1 Misoperation, they must develop and document R2 CAP by 5/30 (not 8/29). 3. We agree with the SERC PCS that introducing time limits is unwarranted and burdensome. Regional Entities now get quarterly Misoperation and CAP status reports and have sufficient information to monitor progress. 4. At most, a one year time limit for CAP completion or explanation of CAP duration could be used. A small number of CAPs will extend beyond one year due to their scope or outage restrictions. SERC has used a two year limit then requiring a formal explanation, and very, very few have reached this time limit.
Response: Thank you for the comments. **1. The drafting team revised Requirement R2 based on your suggestion and modified the Guidelines and Technical Basis section of the standard associated with Requirements R1 and R2.** **2. The drafting team believes the wording is sufficiently clear.** **3. The drafting team disagrees. The drafting team believes the timelines add measurability to the goal of determining cause and developing appropriate corrective actions.** **4. The timeframe for completing the CAP cannot be prescribed in a standard due to external factors such as outage restrictions, availability of parts, capital allocation and other circumstances that can cause a CAP to be delayed. The drafting team believes that entities can reliably manage and assure CAP completions.**		
Kansas City Power & Light	No	1. R2 requires development of a CAP and evaluation of CAP applicability to other locations. I recommend development of a CAP in 60 days for the specific location

Organization	Yes or No	Question 3 Comment
		where the misoperation occurred. CAP applicability to other locations may require more time depending on what the CAP involves. CAP applicability to other locations should be allowed a longer time frame such as 12 months. 2. R3 requires development of an action plan for misoperations with an unknown cause. Depending on the type of protection equipment in place it may not be possible to always determine the cause of every misoperation. For example electromechanical relays only provide targets and event reports may not be available. R3 seems to require that EM relays be changed out to digital relays in order to monitor for the next misoperation. The standard should not require this and R3 should be deleted.
Response: Thank you for the comments. 1. **Requirement R2 specifies a CAP "for the identified Protection System component(s)" and doesn't specify required timeframes for CAP completion which is determined by the entity. It only requires consideration of the Misoperation cause at other locations. It is responsibility of the entity to define when and where to apply a CAP (or not) at "the entity's Protection Systems at other locations." A CAP can be revised to reflect changes in scope and completion date.** 2. **Requirement R3 (bullet 1) doesn't require Protection System modifications but rather the development of an action plan which *could* include Protection System modifications to aid further investigation. Requirement R3 (bullet 1) doesn't specify replacement of electromechanical relays with microprocessor-based devices. The standard includes Requirement R3 to address those instances where there are significant challenges to determining a Misoperation cause and propose other investigative actions. The action plan developed in Requirement R3 allows the entity to set the work timetable and revise that timetable as required.**		
Exelon Corp.		1. The Application Guidelines should be part of the Standard because they provide better clarification of the activities and timelines associated with R1, R2 and R3. 2. For R2: Replace "Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability" with "Explain in a declaration if no further corrective actions are required and your rationale." "beyond the entity's control" may be subjective. Suggest including the following statement based on

Organization	Yes or No	Question 3 Comment
		wording in the Application Guidelines concerning a no CAP declaration: "A condition identified during an investigation that is addressed by existing maintenance activities would be justification for taking no additional corrective action." 3. Exelon comments: Suggest revising the time limit verbiage as follows in order to provide more clarity:R1 Within 120 days of the event, review to determine whether the operation was correct. For any misoperation, identify and document the cause. R2a If after the initial 120 days a cause is determined for the misoperation, within 60 days - Develop a corrective action plan for the identified protection system componentOrExplain in a declaration if no further corrective actions are required and your rationale R2b If after the initial 120 days no cause was determined for the misoperation, within 60 days - Develop an action plan that identifies additional investigative actions to determine the causeOrExplain in a declaration why no further action will be taken R3 Within 60 days of determining a cause under requirement R2b - Develop a corrective action plan for the identified protection system componentOrExplain in a declaration if no further corrective actions are required and your rationale.
Response: Thank you for the comments. **1. The Guidelines and Technical Basis section will be filed as part of the approved standard.** **2. The drafting team has revised the Guidelines and Technical Basis section of the standard for Requirement R2 to include examples of what is meant by "beyond the entity's control".** **3. The drafting team appreciates your suggested revisions to the standard but declines to make the changes.**		
Pepco Holdings Inc & Affiliates	Yes	The timeframes for R1, R2 & R3 are acceptable, since Requirement R3 provides a reasonable alternative if the investigation cannot be completed within the allotted 120 days in R1 (due to outage constraints, severe weather, resources, etc.). However, the commentary in the Rationale for R2 is misleading and incorrect with regard to the statement that 60 days is reasonable for the procurement of funds for a

Organization	Yes or No	Question 3 Comment
		CAP. Capital dollars needed to fund larger CAP's (like other capital improvement projects) are budgeted for during a yearly budget cycle, usually in the fall of the preceding budget year. As such, unless the CAP was small and can be funded by an emergency blanket project it could take up to a year to get the necessary funding approved. We would suggest removing the procurement of funds from the R2 Rationale since it is not a pre-requisite for developing a CAP.
Response: Thank you for the comments. **The drafting team revised the Requirement R2 rationale based upon yours and other comments. The drafting team revised the R2 rationale and removed the "procurement of funds" reference in the Requirement R2.**		
Southwest Power Pool Regional Entity	Yes	With the proposed time limits, NERC may have to clarify how and when entities submit to the RE database misoperations that are still under investigation.
Response: Thank you for the comments. The reporting obligations have been removed from the standard.		
Utility System Efficiencies, Inc.	Yes	See previous comments for questions 1 and 2.
Response: Thank you for the comments. **Please see the responses to your comments on Questions 1 and 2.**		
Idaho Power Co.	Yes	Yes, they seem reasonable.
Response: Thank you.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration believes that 120 days is generally sufficient to determine the root cause of most Misoperations - or to have evaluated and documented multiple possible causes if the source of the Misoperation cannot be determined. The additional 60 days to develop a corrective action plan time frame is acceptable to us as well.

Organization	Yes or No	Question 3 Comment
Response: Thank you for the comment.		
Texas Reliability Entity	Yes	We generally agree with the deadlines, but we have questions about how they apply in a multi-party situation. If a Protection System Misoperation is determined and an entity ("Entity A") determines that the cause of the Misoperation is due to a component owned by another entity (Entity B"), how does the 120 day time period apply? What if Entity A does not start its review until 60 days after the operation and tells Entity B on the 90th day? Entity A has identified the cause (Entity B component) but what timeframe is Entity B under to determine the Misoperation cause for the component? What exactly is Entity A's mandatory obligation, and what is Entity B's mandatory obligation, and what are the applicable deadlines?
Response: Thank you for the comments. **The drafting team revised Requirement R1 based; please review the new Requirement R1. The notified entity has the remainder of the 120 day period per Requirement R1 to determine the cause of the Misoperation; then has at least 60 days to create a CAP or an action plan as stated in Requirements R2 and R3. The drafting team has clarified Requirement R1 to show that the interrupting device owner will do the initial investigation and will contact other Protection System owners only if a correct operation cannot be determined. In this case, the investigative information is passed from the interrupting device owner to the other owners. The standard requires all owners to confirm whether their portions of the Protection System operated correctly or not within 120 days of the interrupting device operation. As stated in the Guidelines and Technical Basis section of the standard, the drafting team expects all owners to work jointly in making these determinations, freely sharing information with each other. Only the owner of a Protection System component that misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting.**		
City of Tallahassee	Yes	In lieu of R3, I agree with this.
Response: Thank you.		
Western Small Entity Comment Group	Yes	

Organization	Yes or No	Question 3 Comment
Associated Electric Cooperative Inc - JRO00088	Yes	
Detroit Edison	Yes	
Tacoma Power	Yes	
Colorado Springs Utilities	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
Duke Energy	Yes	
Project 2010-05.1	Yes	
Western Area Power Administration	Yes	
Okanogan PUD	Yes	
National Grid	Yes	
Wisconsin Electric	Yes	
Tri-State G&T	Yes	
Clark Public Utilities	Yes	
New York Power Authority	Yes	

Organization	Yes or No	Question 3 Comment
Orange and Rockland Utilities	Yes	
The United Illuminating Company	Yes	
US Bureau of Reclamation	Yes	
Liberty Electric Power LLC	Yes	
Consumers Energy	Yes	
Cogentrix Energy, LLC	Yes	
Independent Electricity System Operator	Yes	
City of Tallahassee	Yes	
Essential Power, LLC	Yes	
Oncor Electric Delivery	Yes	

4. **The team has modified the standard to address Misoperations when two or more entities own separate components in a Protection System. Do you agree that the standard adequately deals with this situation? If not, please provide specific reasons why not and alternative recommendations.**

Summary Consideration:

Numerous commenters were confused about which entity was responsible for what actions when multiple owners were involved in an operation. The drafting team revised Requirement R1 to clarify that only the owner of a Protection System component that Misoperated is responsible for documenting the findings, and developing a CAP or action plan.

A few commenters were concerned about meeting the requirements when a major disturbance occurs, such as a storm. The drafting team believes this issue is covered by the NERC Sanction Guidelines as discussed in the Guidelines and Technical Basis section of the draft standard. No changes to the standard were made to specifically address this issue.

A few commenters were concerned about ensuring cooperation between entities. The drafting team believes this issue is adequately addressed in the Guidelines and Technical Basis section of the draft standard. No changes to the standard were made to specifically address this issue.

A few commenters felt having formal notification to another entity of an operation was unnecessary. The drafting team disagreed and clarified Requirement R1 to show that the interrupting device owner will do the initial investigation and will contact other Protection System owners only if a correct operation cannot be determined. In this case, the investigative information is passed from the interrupting device owner to the other owners.

A few commenters were concerned with the definition of "suspects" in triggering notification. The drafting team revised Requirement R1 to eliminate "suspects". The trigger for notification is now if the interrupting device owner cannot determine that an operation is correct.

A few commenters wanted a time period for a notified entity to do its own investigation. The drafting team declined to make this change. The notified entity has the remainder of the 120 day period, and if needed can establish an action plan with its own time table for further investigation to determine whether their component operated correctly.

A few commenters were concerned with the burden of tracking notifications, especially involving "receipts" from other entities. The drafting team revised Measure M1 to eliminate "receipts".

Organization	Yes or No	Question 4 Comment

Organization	Yes or No	Question 4 Comment
Pepco Holdings Inc & Affiliates	No	The responsibility for R1 through R4 should be on the owner of the Protection System which initiated the interruption of a BES facility and not the owner of the interrupting device. See extensive comments on this subject in our response to Question 2 (Requirement R1).
Response: Thank you for your comment. **Please see our response in Question #2.**		
Southwest Power Pool Reliability Standards Development Team	No	1) There is an issue with the timing and requesting data from these other entities that own part of the protection system. There isn't a time frame for the other entity to return the data requested and seems like this could cause an entity to not meet the time frames specified in the requirements. 2) Also going back to the Major disturbance if multiple entities are hit then they will be busy taking care of their own operations and may not have time to coordinate the data request in a timely manner.
Response: Thank you for your comment. **1) The drafting team has clarified Requirement R1 to show that the interrupting device owner will do the initial investigation and will contact other Protection System owners only if a correct operation cannot be determined. In this case, the investigative information is passed from the interrupting device owner to the other owners. The standard requires all owners to confirm whether their portions of the Protection System operated correctly or not within 120 days of the interrupting device operation. As stated in the Application and Guidelines section, the drafting team expects all owners to work jointly in making these determinations, freely sharing information with each other. Only the owner of a Protection System component that Misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting.** **2) 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 major disturbances, 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.**		

Organization	Yes or No	Question 4 Comment
Tacoma Power	No	Remove the second sentence under R1.1. At minimum, consider moving this sentence to R1.3 or creating a new R1.4. As written, this sentence is included in a sub-requirement that, in the overall process, has not yet even required designation of any Mis-operations. Presumably, at least part of the reason that this sentence was included was to mitigate any concerns that Entity A will wait before notifying Entity B, such that Entity B has little time to investigate before the deadline. However, as written, R1.1 would still permit Entity A to notify Entity B within 120 calendar days of the interrupting device operation, which would leave Entity B no time to investigate before becoming non-compliant, since per R1 the clock for investigation starts when the interrupting device operated. The bottom line is that, if Entity A suspects that a component owned by Entity B contributed to a Mis-operation, it is in Entity A's interest to take action; it is recommended that there be no explicit regulaotory requirement for notification.
Response: Thank you for your comment. **The drafting team revised Requirement R1; please review the new Requirement R1. The notified entity has the remainder of the 120 day period per Requirement R1 to determine the cause of the Misoperation; then has at least 60 days to create a CAP or an action plan as stated in Requirements R2 and R3. The drafting team believes notification is needed to formally involve other Protection System component owners in resolving a potential Misoperation.**		
El Paso Electric	No	See EPE's comment in Question 2.
Response: Thank you for your comment. **Please see our response in Question #2**		
Santee Cooper	No	Initially, the investigation/reporting burden should fall on the owner of the interrupting device. However, once it is determined which entity's equipment caused the misoperation, the burden of reporting should shift to that entity.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. **The drafting team agrees with your comment and revised Requirement R1 for clarity.**		
Dominion	No	a). Subpart 1.1 does not provide for a clear hand-off when another entity's Protection System component contributed to a Misoperation of the first party. Specifically, it appears that the first party will have to develop its CAP to include a component owned by another entity and for which it has no control. The Application Guideline speaks to the need for various component owners to cooperate in the investigation and contact the Regional Entity should there be a lack of cooperation. This guidance needs to be clarified in the Requirement as compliance is measured against the Requirement, not guidance. Suggest adding Subpart 1.2 to state: "If notified by an entity that a Protection System component contributed to that entity's Misoperation, than It is expected that all the owners will communicate with each other, sharing any information freely, so that operations can be analyzed, Misoperations identified and corrective actions taken." If adopted by the SDT, then renumber existing Subparts 1.2 and 1.3 to 1.3 and 1.4 respectively. b). R1 correctly requires the interrupting device owner to initiate the investigation, but when the Protection System interconnects with another entity and there are indications that the other entity Protection System components misoperated (ie. Other entity sends a spurious DTT), then once the location of the Misoperation is agreed to by the various Protection System owners, then it should be the responsibility of the owner of the Protection System that misoperated to report thus removing the burden of reporting from the interrupted device owner. In some cases there may be several devices interrupted which are owned by different owners and the Protection System failure was due to a Protection System failure by an entity that had no devices that were interrupted at the location where the Misoperation occurred. Under the present PRC-004-2a, there is confusion on this distinction. The process (especially reporting process and resubmittals) is simplified when the owner of the Protection System that misoperated is responsible for: interfacing with others

Organization	Yes or No	Question 4 Comment
		to analyze, developing CAP, implementing CAP and reporting. c). There is also a suggestion that multiple entities utilize a joint investigation report. Again, the burden of reporting should lie on the entity that had the Protection System Misoperation to initiate reports and communicate other entity actions.
Response: Thank you for your comment. **1) The drafting team has clarified Requirement R1. Only the owner of a Protection System component that Misoperated is responsible for documenting the findings, and developing a CAP or action plan. The drafting team believes the wording in the Guidelines and Technical Basis section of the standard is sufficient.** **2) The drafting team agrees with your comment and has revised Requirement R1 for clarity.** **3) The drafting team agrees with your comment. Entities may work together to create a single investigation report. Only the owner of a Protection System component that Misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting. The drafting team clarified this in the Guidelines and Technical Basis section of the standard.**		
Luminant	No	Luminant disagrees with the concept of "If an entity suspects ..." phrase. Luminant suggests that the data exchange between entities with "interpendent System protection Systems" be as follows: "...For its Protection System operations that are interdependent with the Protection Systems of another owner, the entity shall notify the owner of the interdependent Protection System." The owner of other components in the Protection System may request information in performing their investigation.
Response: Thank you for your comment. **The drafting team believes notifying every owner every time an operation occurred, especially when the interrupting device owner knows the operation is correct, would be burdensome. The drafting team does agree "suspects" is vague and has changed Requirement R1 to make the notification trigger clearer.**		
SERC Protection and Control	No	1. Please refer to comments in #2 above (SERC comments 2 and 3). Also, consider the following:a). R1 correctly requires the interrupting device owner to initiate the

Organization	Yes or No	Question 4 Comment
Subcommittee (PCS)		investigation, but when the Protection System interconnects with another entity and there are indications that the other entity's Protection System components misoperated (i.e. Other entity sends a spurious DTT), then once the cause of the Misoperation is determined, it should be the responsibility of the Protection System owner that misoperated to report; thus removing the burden of reporting from the interrupted device owner. In some cases there may be several devices interrupted which are owned by different entities and the Protection System failure resulted from an entity that had no devices that were interrupted or affected at the location where the Misoperation occurred. Under the present PRC-004-2a, there is confusion on this distinction. b). There is also a suggestion that multiple entities utilize a joint investigation report. Again, the burden of reporting should lie on the entity that owns the Protection System that caused the Misoperation and they should initiate reporting and communicating other entity actions to correct the problem.
Response: Thank you for your comment. For your comments in Q2, Please see our response in Question #2. **a) The drafting team agrees with your comment and has revised Requirement R1 for clarity.** **b) The drafting team agrees with your comment. Entities may work together to create a single investigation report. Only the owner of a Protection System component that misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting. The drafting team clarified this in the Guidelines and Technical Basis section of the standard.**		
ACES Power Marketing Standards Collaborators	No	(1) There is no justification in the Rationale for R1 or in the Application Guidelines to show statistics that this scenario would occur regularly. The supplemental documents do not explain why the SDT felt that adding this provision to the standard was necessary. This concept seems to be a rare instance without a basis for adding it as a requirement. Considering that this requirement is on a timeline for which compliance would be measured. (2) The requirement's wording is subjective in nature and would be very difficult to provide documentation for "suspecting" another entity's component contributed to the Misoperation. Also, R1.1 seems to

Organization	Yes or No	Question 4 Comment
		skip a step - first the entity identifies and reviews all operations but the next step should be to identify Misoperations. Once Misoperations are identified, then the investigation for the cause of the Misoperation would occur. The investigation step is when an entity would consider if another entity's components or equipment would have been the cause to the Misoperation. Therefore, we recommend striking the second sentence of 1.1.
Response: Thank you for your comment. **1) The drafting team is aware of multiple instances where the components of a Protection System are shared. The interface between TOs and GOs at a switchyard is a very common example. Requirement R1 was written to address these kinds of issues.** **2) The drafting team does agree "suspects" is vague and has changed Requirement R1 for clarity.**		
Bonneville Power Administration	No	1. BPA believes the standard does not provide enough clarity for dealing with the different ownership arrangements. 2. In addition, BPA prefers not to be required to notify other owners of misoperations in their protection systems, as each owner should be responsible for reviewing the operations on their own equipment.
Response: Thank you for your comment. **1. The drafting team agrees with your comments and revised Requirement R1 for clarity.** **2. Interrupting device owners will notify other entities only if they are unable to determine if an operation was correct. Each owner is responsible for determining if their equipment functioned correctly.**		
GTC	No	a). R1 correctly requires the interrupting device owner to initiate the investigation, but when the Protection System interconnects with another entity and there are indications that the other entity Protection System components misoperated (ie. Other entity sends a spurious DTT), then once the cause of the Misoperation is determined, then it should be the responsibility of the Protection System owner that

Organization	Yes or No	Question 4 Comment
		caused the misoperation to report thus removing the burden of reporting from the interrupted device owner. In some cases there may be several devices interrupted which are owned by different entities and the Protection System failure was due to a Protection System failure by an entity that had no equipment that was interrupted or affected at the location where the Misoperation originated. Under the present PRC-004-2a, there is confusion on this distinction. b). There is also a suggestion that multiple entities utilize a joint investigation report. Again, the burden of reporting should lie on the entity that owns the Protection System that caused the Misoperation and they should initiate reporting and communicating other entity actions to correct the problem.
Response: Thank you for your comment. For your comments in Question #2, please see our response in Question #2. **a) The drafting team agrees with your comment and has revised Requirement R1 for clarity.** **b) The drafting team agrees with your comment. Entities may work together to create a single investigation report. Only the owner of a Protection System component that Misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting. The drafting team clarified this in the Guidelines and Technical Basis section of the standard.**		
JEA	No	R1.1 requires that if an entity suspects a Protection System component(s) owned by another entity contributed to a Misoperation then we are to notify the owner of that Protection System component and provide any requested investigative information. We recommend to add language such as the notified entity must provide any requested information.
Response: Thank you for your comment. **The drafting team believes that such language is not necessary. It is expected that all the owners will communicate with each other, sharing any information freely, so that operations can be analyzed, Misoperations identified and corrective actions taken. Please see the Guidelines and Technical Basis section of the standard for Requirement R1. The drafting team believes the initial notification was necessary to ensure all Protection System component owners were aware that an operation took place and that**		

Organization	Yes or No	Question 4 Comment
these owners needed to investigate the operation of their components for correctness.		
Southwest Power Pool Regional Entity	No	If Owner A notifies Owner B that Owner B's component contributed to a misoperation, after being notified, Owner B should be responsible for performing misoperations analysis and reporting. The way the standard reads, there is no responbility for Owner B to investigate a component that didn't operate but did contribute to a misoperation.
Response: Thank you for your comment. **The drafting team has revised Requirement R1 to clarify the overall process. Each owner is responsible for determining if their equipment functioned correctly.**		
Nebraska Public Power District	No	I have concerns with the requirement R1.1 and M1 related "demonstrating transmittal and receipt of information" such as saving correspondence or communications (notifications) with other entities as part of the analysis and corrective actions with this standard. The misoperation is identified and fixed (or not fixed) by means necessary for the involved entities following the other requirements. This requirement will add time burden for tracking communications that takes away from the goal to fix the issue. It also confuses the issue on who is responsible if a "receipt" of notification cannot be obtained. This would increase the difficulty for auditing as well and adds a subjective nature to what is considered acceptable correspondence. I recommend this part of R1 be removed or the proof that a transmitted notification was received by another entity not be required since that is not under the control of the sending entity. Also, rather than tracking numerous emails and notifications the option for lack of response is to appeal to the RE for help as stated in the application guidelines. It may be wise to have a contact/process at the RE assigned to follow up on these types of requests especially if the associated entity is not registerd.
Response: Thank you for your comment.		

Organization	Yes or No	Question 4 Comment
The requirement only specifies tracking the initial notification. Measure M1 was revised to remove "and receipt". This notification is required only in cases where the interrupting device owner cannot determine if an operation is correct. The drafting team believes the number of potentially incorrect operations would be small enough that it should not be a burden.		
PacifiCorp	No	See comment #3
Response: Thank you for your comment. Please see our response in Question #3		
Southern Company	No	o It is noted in the Rational box for R1 that the owner of the component that cause the misop will create the CAP, etc. As such it is not clear who will report the Misoperation. i.e. If Owner A has a breaker open for a fault outside the zone due to a carrier that failed to send a block signal. Is an entities only responsibility to communicate to the other owner that his equipment didn't operate correctly? If so how do they know he ever reported it and/or did anything to correct the problem. It seems that the misoperation should be reported by the entities whose interrupting device opened in error. o Please clarify the statement in the Rational Box for R1: "The initial investigation documentation should be provided to the owner of the Protection System component(s) that contributed to the Misoperation, upon request.
Response: Thank you for your comment. The drafting team revised Requirement R1 and its rationale box to more clearly indicate who is responsible for what actions. Only the owner of a Protection System component that misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting.		
ITC	No	1. It is unclear between R1 and R4 who needs to report the misoperation. R4 should specify the owner of the component that initiated the misoperation as the reporter so that a single misoperation is not reported by multiple entities. 2. In 1.1 once notified, the other entity should be allowed additional time (possibly another 120 days?) to analyze the Protection System operation to determine the

Organization	Yes or No	Question 4 Comment
		component that malfunctioned. As written there is only a single timeframe beginning with the outage.The word 'necessary' should be included between 'any' and 'requested' in R1.1.
Response: Thank you for your comment. 1. **The drafting team revised Requirement R1 to more clearly indicate who is responsible for what actions. Only the owner of a Protection System component that misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting.** 2. **The drafting team revised Requirement R1 based; please review the new Requirement R1. The notified entity has the remainder of the 120 day period per Requirement R1 to determine the cause of the Misoperation; then has at least 60 days to create a CAP or an action plan as stated in Requirements R2 and R3.**		
Cleco Corporation	No	1) There is an issue with the timing and requesting data from these other entities that own part of the protection system. There isn't a timeframe for the other entity to return the data requested and seems like this could cause an entity to not meet the timeframes specified in the requirements. 2) Also going back to the Major disturbance if multiple entities are hit then they will be busy taking care of their own operations and may not have time to coordinate the data request in a timely maner.
Response: Thank you for your comment. 1. **The drafting team has clarified Requirement R1 to show that the interrupting device owner will do the initial investigation and will contact other Protection System owners only if a correct operation cannot be determined. In this case, the investigative information is passed from the interrupting device owner to the other owners. The standard requires all owners to confirm whether their portions of the Protection System operated correctly or not within 120 days of the interrupting device operation. As stated in the Guidelines and Technical Basis section of the standard, the drafting team expects all owners to work jointly in making these determinations, freely sharing information with each other. Only the owner of a Protection System component that misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting.**		

Organization	Yes or No	Question 4 Comment
2. 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 major disturbances, 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.		
Tri-State G&T	No	It is not clear how the owner of the interrupting device that operates can designate and investigate the Misoperation of a Protection System component owned another entitity, but that seems to be what Parts 1.2 and 1.3 require. One solution would be to divide Requirement R1 into two requirements as described below."R1. Within 120 calendar days of an interrupting device operation in its Facility caused by a Protection System operation, each Transmission Owner, Generator Owner, and Distribution Provider shall identify and review each Protection System operation. If the entity suspects a Misoperation of a Protection System component owned by another entity caused an unnecessary interrupting device operation, notify the owner of that Protection System component and provide any requested investigative information.""R2. The owner of any Protection System identified as misoperating in Requirement R1 shall: 2.1 Designate each Misoperation. 2.2 Investigate each Misoperation and document the findings including a cause for each Misoperation, if identified. 2.3 Provide its Corrective Action Plan (CAP) to the other entity and notify the other entity upon completion of the CAP if the Protection System that Misoperated caused that other entity's interrupting device to operate."
Response: Thank you for your comment. **The drafting team has clarified Requirement R1 to show that the interrupting device owner will do the initial investigation and will contact other Protection System owners only if a correct operation cannot be determined. In this case, the investigative information is passed from the interrupting device owner to the other owners. The standard requires all owners to confirm whether their portions of the Protection System operated correctly or not within 120 days of the interrupting device operation. As stated in the Guidelines and Technical Basis section of the standard, the drafting team expects all owners to work jointly in making these determinations, freely sharing information with each other. Only the owner of a Protection System component that**		

Organization	Yes or No	Question 4 Comment
misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting.		
American Electric Power	No	Please see our response to Question 2 where we suggest changes to R1 regarding such situations.
Response: Thank you for your comment. **Please see our response in Question #2.**		
Portland General Electric Company	No	There is a requirement to notify another entity if their component is suspected of contributing to a misoperation, but there is no requirement to respond to such notifications. Accountability to report back to the entity providing the notification should be included to ensure that entity can maintain its own compliance. Events involving transfer trip on interconnections, for example, could involve misoperations of equipment owned by both entities and require significant cooperation during the investigation phase.
Response: Thank you for your comment. **It is expected that all the owners will communicate with each other, sharing any information freely, so that operations can be analyzed, Misoperations identified and corrective actions taken. Please see the Guidelines and Technical Basis section of the standard for Requirement R1. The drafting team believes the initial notification was necessary to ensure all Protection System component owners were aware that an operation took place and that these owners needed to investigate the operation of their components for correctness. Only the owner of a Protection System component that misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting.**		
Ingleside Cogeneration LP	No	It is not clear to Ingleside Cogeneration LP how a situation is resolved where interconnected Protection System owners disagree with the causes or mitigation of a Misoperation. We can easily envision a scenario where we have been informed by a neighbor that one of our relays contributed to a Misoperation - which we do not find to be the case. This seems like it could result in an audit finding that we did not report a Misoperation based upon someone else’s evaluation.There may be recourse

Organization	Yes or No	Question 4 Comment
		in existing escalation procedures to engage the Regional Entity and even NERC at some point to resolve a conflict of this nature. Whatever the solution, we firmly believe that this pathway to resolution must be made clear as part of this project. If left open, the most subtle interaction issues will result in finger pointing in all directions - an unproductive use of everyone's time. Furthermore, problems of this nature are likely to identify previously unknown failure mechanisms, which could help all industry stakeholders. The Regions may have access to technical specialists who are best positioned to assist with an evaluation of this level of complexity.
Response: Thank you for your comment. **As stated in the Guidelines and Technical Basis section of the standard, the drafting team expects all owners to work jointly in making these determinations, freely sharing information with each other. The drafting team believes that owners almost always work together to resolve these issues. If an entity cannot reach agreement, but believes a Misoperation has occurred, it may involve its Regional Entity for help resolving the Misoperation.**		
Texas Reliability Entity	No	(1) We voted "no" on this draft because it is unclear who is responsible for various actions in multi-owner situations. The requirements need to clearly state who is responsible for compliance with each step of the identification, investigation, correction and reporting process. (2) We suggest that the team consider a solution such as: (a) the owner of the interrupting device should be required to identify the Misoperation and the suspected component that caused it, and then (b) the owner of the suspected component should be required to take the further steps to investigate and correct the problem and to submit the required reports. (3) Additional language is needed to clarify that, for Misoperation investigation and reporting purposes, the entity that owns the component that misoperated is required to submit the reports. Also, any CAP's should include the review of coordination issues between entities involved in the Misoperation.
Response: Thank you for your comment. **The drafting team has revised Requirement R1 to clarify who is responsible for what actions. Only the owner of a Protection**		

Organization	Yes or No	Question 4 Comment
System component that misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting.		
PSEG	No	We believe that our alternative language in #2 and #3 above is clearer. In addition, a Misoperation analysis is required even when a cause cannot be determined. After that analysis is completed, an entity either develops a CAP or an action plan.
Response: Thank you for your comment. **Please see our response in Questions #2 & #3. The drafting team agrees that an analysis is required and the findings must be documented every time a Misoperation occurs, whether or not a cause is found.**		
Consumers Energy	No	R1.1 seems to be intending that the owner of the interrupting device perform the intial investigation. If a Misoperation is identified and the Protection System is owned by another entity, the wording of the standard is not clear about which entity should be responsible for the CAP, etc. The rationale paragraph covers this, but of course won't be included once the standard is finalized. Are both entities responsible for documenting the operation/Misoperation?
Response: Thank you for your comment. **The drafting team revised Requirement R1 to clarify who is responsible for what actions. Only the owner of a Protection System component that misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting.**		
CenterPoint Energy	No	(a) CenterPoint Energy recommends deleting the second sentence in R1.1 that states: "If the entity suspects a Protection System component(s) owned by another entity contributed to a Misoperation, notify the owner of that Protection System component and provide any requested investigative information." CenterPoint Energy believes it is unnecessary to have a requirement to force entities to coordinate on misoperation analysis and corrective action, as there are existing avenues that are available, if necessary.(b) The CenterPoint Energy comments in Question 2 are related to this question. Establishing the applicability to the owner of the protective relays would establish the entity responsible for misoperations

Organization	Yes or No	Question 4 Comment
		reporting. CenterPoint Energy recommends R1 maintain only the wording from R1.3, resulting in the following wording for R1: "Investigate each Misoperation (if any) and document the findings including a cause for each Misoperation, if identified."
Response: Thank you for your comments. **a) The drafting team believes it is necessary to require communication in the standard. It is possible the owner of the Protection system component that misoperated will not be in a position to know that a Misoperation has occurred. Since they must meet the requirements in this standard, requiring communication ensures they will know they need to investigate.** **b) See our response in Question #2. The drafting team agrees that the owner of the Protection System component that misoperated is responsible for the CAP or action plan and reporting. The drafting team has revised Requirement R1 for clarity.**		
Detroit Edison	Yes	Yes - SDT did an excellent job with joint ownership issues.
Response: Thank you.		
Western Area Power Administration	Yes	An entity cannot be held responsible for another entity's failure to respond or act upon notice of a suspected misoperation.
Response: Thank you for your comment. **The drafting team revised Requirement R1 and Measure M1. Only the owner of a Protection System component that misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting.**		
Exelon Corp.	Yes	o The standard needs to make it clear that an entity needs to provide information to another entity within a specified time period, e.g., a TO needs to provide information to a GO on a transmission line trip, within limitations of the FERC Standards of Conduct.
Response: Thank you for your comment. **Requirement R1 mandates all investigative work, including the passing of investigative information, be performed within 120 days**		

Organization	Yes or No	Question 4 Comment
of the interrupting device operation.		
Ameren Services	Yes	Yes, as long as the R1 rationale is augmented to clarify reporting responsibility as we recommend in items 2 and 3 of question 2 above.
Response: Thank you for your comment. Please see our responses in Questions 2.		
Northeast Power Coordinating Council	Yes	
Western Small Entity Comment Group	Yes	
Associated Electric Cooperative Inc - JRO00088	Yes	
Colorado Springs Utilities	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
Duke Energy	Yes	
Project 2010-05.1	Yes	
Operational Compliance	Yes	
TVA Transmission Operations and Maintenance	Yes	

Organization	Yes or No	Question 4 Comment
Okanogan PUD	Yes	
National Grid	Yes	
seattle city light	Yes	
Wisconsin Electric	Yes	
Manitoba Hydro	Yes	
NorthWestern Energy	Yes	
Clark Public Utilities	Yes	
Utility System Efficiencies, Inc.	Yes	
Idaho Power Co.	Yes	
LCRA Transmission Services Corporation	Yes	
Dairyland Power Cooperative	Yes	
Orange and Rockland Utilities	Yes	
Public Service Company of New Mexico	Yes	
City of Austin dba Austin Energy	Yes	

Organization	Yes or No	Question 4 Comment
Modesto Irrigation District	Yes	
US Bureau of Reclamation	Yes	
Liberty Electric Power LLC	Yes	
Los Angeles Department of Water and Power	Yes	
Cogentrix Energy, LLC	Yes	
Independent Electricity System Operator	Yes	
Sacramento Municipal Utility District	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
NextEra Energy Inc.	Yes	
Essential Power, LLC	Yes	
Oncor Electric Delivery	Yes	
Kansas City Power & Light	Yes	
New York Power Authority	Yes, Yes	

Organization	Yes or No	Question 4 Comment
City of Jacksonville Beach, FL dba/ Beaches Energy Services		(No Comment.)

5. **Attachment 1 lists and describes the data to be included in the quarterly reporting. Do you believe this data is appropriate for metric analysis? If not, please provide specific suggestions for improvement.**

Summary Consideration:

After consultation with NERC Legal staff and NERC's ERO Reliability Assessment and Performance Analysis group, the drafting team is removing the reporting obligations from the draft standard. The language in Compliance Section C 1.4 - Additional Compliance Information of the draft standard referencing reporting and Attachment 1 has been deleted. Also, because Attachment 1 was a reference document associated with the Quarterly Misoperation Reporting Form, it will not be posted with the draft standard. The removal of the reporting obligation from the draft standard does not result in a reduction of reliability. Compliance Section C 1.2 - Evidence Retention portion of the draft standard requires entities to retain evidence of compliance for audit and compliance purposes. Reporting is enforceable under NERC's Rules of Procedure, and NERC is currently in the process of preparing a data request under Section 1600 of the NERC Rules of Procedure. NERC would analyze the data collected pursuant to the data request, if approved, to develop meaningful metrics, identify trends in Protection System performance that negatively impact reliability, to identify remediation techniques, and publicize lessons learned for the industry. The data submitted as part of the proposed Section 1600 data request would not be used for compliance or enforcement purposes.

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council	No	An additional field should be added to improve the metric analysis of microprocessor relay malfunctions. For example, the field value for a microprocessor relay malfunction could include the following:Setting Error-Incorrect Numerical Input SpecifiedSetting Error-Incorrect User-Programmed Custom LogicIncorrect Design-Incorrect User ApplicationIncorrect Design-WiringFirmware Version Mismatch by UserOthers
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Tacoma Power	No	1) Why does an entity need to provide the Date Reported? It seems like the Regional Entity could provide this information based upon when they receive it. The person assembling the reporting data may not be the one actually submitting

Organization	Yes or No	Question 5 Comment
		it to the Regional Entity, and the submittal date may not coincide with dated that the reporting data is assembled. Therefore, two individuals may need to be involved. While not a lot of extra work, it is an additional administrative step in the process that seems to provide little value to reliability. 2) Additional information, or at least a reference to additional information, should be provided to describe TADS and GADS reportable events. 3) It seems like the following fields could be consolidated into one: Event Description/Analysis and Protection Systems/Components that Misoperated. 4) What penalties would be likely if an entity, acting in good faith, provides information that is later determined to be incorrect and is then updated in another reporting period? 5) Do all Mis-operations need to be submmitted with Submittal Type entered as ‘Remove’ before they no longer need to be resubmitted? Or, does the final submittal only need to have one of the following in the Resolution Status field, even if the Submittal Type is ‘New’ or ‘Update’:‘Corrective Action Plan - Completed,’ ‘Action Plan - Completed,’ or ‘Declaration - Completed.’If a declaration is made, or an action plan is completed, and reported (submitted), does the associated Mis-operation need to be continually re-submitted while the status is ‘Declaration - Completed’ or ‘Action Plan - Completed’? It seems like these two statuses are still somewhat open-ended. 6) Remove double slash in “Corrective Action Plan//Declaration Development Date.”
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
El Paso Electric	No	EPE believes the columns in Attachment 1 requesting Event Analysis Completion Date; Corrective Action Plan/Declaration Development Date; or Action Plan/Declaration Development Date does not contribute to improving protection system performance.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Santee Cooper	No	The Incorrect Setting/Logic/Design Errors category needs to be split into separate categories to improve the data analysis. As relays get more complex, more of the protection system is becoming internal to the relay, and so this has become a disproportionately large category.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Dominion	No	a). Eliminate the field “Additional BES Interruptions”. This places unnecessary burden on entities to report interruptions that may not be associated with a Power System Misoperation. There is no need to track or collect this additional input. b). Instruction for Attachment 1 needs to include specific information as to when to fill out specific data in this field. The template currently requires a brief description in the Event Description field and details in the Corrective Action field when classified as Corrective Action in Progress. Once the Corrective Action Plan is completed, the instructions say to clear this field (which we disagree with) and input cause information under the Event Description field. Recommend renaming this field from Event Description/Analysi to Event Description.c). d). There should be a means to separate Generation and Transmission. This approach doesn’t appear to give entities the option of separating reports. e). Please split Incorrect Setting/Logic/Design Errors into three separate categories to improve the usefulness of the metrics regarding Protection System performance. Provide examples how to separate settings from logic when it’s all part of a smart relay setting. f). Please split Communication Failure into two separate categories, one for ‘Power

Organization	Yes or No	Question 5 Comment
		Line Carrier' and one for 'non-Carrier' to improve the usefulness of the metrics regarding Protection System performance. g). Please eliminate the TADS and GADS information. TADS only counts lines and transformers that operate, not any other equipment. Instead request the total number of operations at each Equipment Voltage level because this is a more effective means of gathering the information for all Protection System operations. However the definition of an operation and rules for determining the number of operations will need some clarity. h). Drop the word "general" in the field name Misoperation General Cause". No need to introduce another undefined descriptive word. i). Remove the following fields: "Event Analysis Completion Date", "Corrective Action Plan/Declaration Development Date", and "Action Plan/Declaration Development Date". j). Revise "Target Resolution Completion Date" to "Resolution Target Date". k). Revise "Actual Resolution Completion Date" to "Resolution Completion Date". l). Prevent entry of data into a field that was made not applicable by a previous field selection.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Luminant	No	1) The data provided by the quarterly report would have little, if any, reliability benefit to the BES due to the limited technical information provided in the Attachment. 2) Luminant recommends that a report be provided on an annual basis.
Response: Thank you for your comments.		

Organization	Yes or No	Question 5 Comment
Please read the Summary Consideration for Question 5.		
SERC Protection and Control Subcommittee (PCS)	No	1) Please change 'Time Zone' Field Value to prevailing time (e.g. CPT for Central Prevailing Time) to make reporting more efficient. 2) Please split Incorrect Setting/Logic/Design Errors into three separate categories to improve the usefulness of the metrics regarding Protection System performance. 3) Please split Communication Failure into two separate categories, one for 'Carrier' and one for 'non-Carrier' to improve the usefulness of the metrics regarding Protection System performance. 4) Please eliminate the TADS and GADS data submittals. Instead request the total number of operations at each Equipment Voltage level because this is a more effective means of gathering the information for all Protection System operations. The SERC PCS recommends that the rules for determining an "operation" be consistent between TADS and PRC-004 reporting. Also need to coalesce data systems (GADS, TADS , PRC-004, etc.)
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Colorado Springs Utilities	No	Attachment 1 does not describe data that is appropriate for metric analysis for a couple reasons: (1) This standard applies to both Generation Owners (GOs) and Transmission Owners (TOs); however, GOs are not in a position to respond to the last item on page 1, "Additional BES Interruptions." GOs are responsible for BES equipment in their plants and are not responsible for BES equipment belonging to TOs. Therefore, GOs should not be responsible for determining any BES interruptions outside of the plants. We recommend removing the section, "Additional BES Interruptions". (2) If TADS/GADS data is required for metric analysis, then an explanation should be

Organization	Yes or No	Question 5 Comment
		provided for why the data is required. We recommend that NERC or the Regional Entity provide an explanation for the relevance of the TADS/GADS data to the metric analysis.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
PPL Corporation NERC Registered Affiliates	No	a. GOs are not in a position to respond to the last item on p.1, "Additional BES Interruptions." We know only what happens in our plants, not repercussions on the grid. b. The "slow trip" entries in the "Misoperations Category" do not apply for the majority of Misoperations reported by GOs. The presence of such categories in the draft standard appears to derive from the belief that millisecond-resolution records of Misoperations are always available from DME; but, when this equipment is present at generation plants, it is installed only at the GSU and (if the GO is the owner) the yard breaker - that is, on high-side equipment. The DME is consequently not expected to yield any useful information for Faults occurring at the generator or other low-side components. Notes should be added to PRC-004-3 and the Application Guidelines to the effect that DME downloading and speed-of-response analysis pertain at generation Facilities only when DME is present and only to incoming Faults from the grid.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Bonneville Power Administration	No	BPA believes the data needed for metric analysis depends on what NERC hopes to learn from the data.
Response: Thank you for your comment.		

Organization	Yes or No	Question 5 Comment
Please read the Summary Consideration for Question 5.		
GTC	No	1) Please change 'Time Zone' Field Value to prevailing time (e.g. CPT for Central Prevailing Time) to make reporting more efficient. 2) Please split Incorrect Setting/Logic/Design Errors into three separate categories to improve the usefulness of the metrics regarding Protection System performance. 3) Please split Communication Failure into two separate categories, one for 'Carrier' and one for 'non-Carrier' to improve the usefulness of the metrics regarding Protection System performance.
Response: Thank you for your comments. Please read the Summary Consideration for Question 5.		
ISO/RTO Standards Review Committee	No	It is unclear whether or not Attachment 1 is part of the standard that must be complied with. The SDT should clarify whether the misoperation information listed in Attachment 1 must be provided as specified. If that is the expectation, then the data requirements must be stipulated as a Requirement. As an Attachment without associated Requirements, we interpret that data submission as not mandatory.
Response: Thank you for your comment. Please read the Summary Consideration for Question 5.		
JEA	No	1) Attachment 1 Field Name: Misoperational General Cause Field Value: Incorrect settings/Logical Design Errors are not a misoperation since the protection system operated exactly as it was programmed. Improper setting should be handled in PRC-005 (maintenance and testing). If we are going to include things that cause a protection system to not protect then there is little justification for not considering other equally as destructive problems such as the breaker opening slowly. It is inconsistent to send the message that human error is a problem but

Organization	Yes or No	Question 5 Comment
		mechanical error is not. Also by excluding human error they could better correlate with TADS, since TADS excludes human error for relay settings. 2) Section 1.4 clearly shows this is a requirement and so if it is required then make it a requirement and if it is not required then delete it.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Nebraska Public Power District	No	1) Need clarification on these items:For Registered Entity ID#: What is the option to fill in the field if the portion of the protection system that misoperated is owned by a non registered entity? 2) The fields Event Analysis Completion Date, Corrective Action Plan/Declaration Development Date, Action Plan/Declaration Development Date seem like they would not have much metric value and add extraneous information. These should be removed. 3) For the Reported By, Phone Number, and E-mail Address line items is this the compliance contact # for a utility or a specific person writing the report? Using specific names, email, and phone numbers can create issues either way. Perhaps it would be best to use more general contact information for the entities or a single point of contact so these line items would stay more constant.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Southern Company	No	1) This list is not inclusive of the present RAPA form. The SDT should insure that the RAPA form is modified to only include the data specified in the Standard. 2) o The TADS information should be removed since there are plans to start reporting # of operations thereby allowing appropriate metric analysis o 3) However, we have a number of recommendations intended to improve the structure and clarity of the standard and Attachment 1: a) The requirement

Organization	Yes or No	Question 5 Comment
		for reporting should be in the Requirements and Measures section as a requirement rather than in the Compliance section C1.4.â€, Attachment 1 needs to be part of the standard since it is referenced in the standard. 4) b) The Registered Entity ID # is not needed as the data submission occurs via web based portals and the RE knows who is submitting the data based on the log in credentials of the submitter. This information is superfluous. 5) c) The "Event Analysis Completion Date" and "Corrective Action Plan/Declaration Development Date" fields are not required if the combined R1 & R2 suggestion is implemented along with the deadline for these requirements being the report date to the RE. 6) d) There are too many classification choices in the "Resolution Status" field. One of three choices should be adequate to tell the RE what stage of evaluation/resolution is active: 1) Analysis - In Progress, which means [Still Under Investigation]; 2) Analysis - Completed - Corrective Action Plan Pending; 3) Corrective Action - Completed, which means [Investigation Complete, Corrective Action Complete] 7) e) Both the "Target Resolution Completion Date" and the "Actual Resolution Completion Date" fields are not needed. We suggest using only the "Target" date field and have the RE look at the Resolution Status field to determine if the Action Plan is Completed. We believe that all of these reporting dates are not necessary. 8) f) The "Date Reported" field is not needed - the submission due dates are fixed by the RE (and have been repeated on page 21 of the Clean draft standard dated 6 Jul 2012. 9) g) We believe that a linkage to GADS reporting is not necessary. In the many years we have been processing relay operations, we have had no reason to review any GADS information. The mis-opeation reporting and resolutino can be processed without the addition of non-useful information.
Response: Thank you for your comments.		

Organization	Yes or No	Question 5 Comment
Please read the Summary Consideration for Question 5.		
ITC	No	If an entity is required to report a misoperation due to a malfunction of another entity's component, then there should be a space for the other Registered Entity's name.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
seattle city light	No	1) I) There are too many classification choices in the "Resolution Status" field of the report form. An equally effective status report can be delivered using three choices: 1) Analysis In Progress [Still Under Investigation]; 2) Analysis Completed - Corrective Action Plan Pending; 3) Corrective Action Completed [Investigation Complete, Corrective Action Complete] 2) II) The form for GOs should differ from that for TOs, for the following reasons: a. GOs are not in a position to respond to the last item on p.1, "Additional BES Interruptions." We know only what happens in our plants, not repercussions on the grid. 3) b. The "slow trip" entries in the "Misoperations Category" do not apply for the majority of Misoperations reported by GOs. The presence of such categories in the draft standard appears to derive from the belief that millisecond-resolution records of Misoperations are always available from DME; but, when this equipment is present at generation plants, it is installed only at the GSU and (if the GO is the owner) the yard breaker - that is, on high-side equipment. The DME is consequently not expected to yield any useful information for Faults occurring at the generator or other low-side components. Notes should be added to PRC-004-3 and the Application Guidelines to the effect that DME downloading and speed-of-response analysis pertain at generation Facilities only when DME is present and only to incoming Faults from the grid.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Cleco Corporation	No	Our issue is not with the requested data but how the data is submitted. The current spreadsheet is very cubersome and needs to be reformatted.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Wisconsin Electric	No	Under Equipment Type: Add an equipment Type, such as "Generator Tie Line", to indicate the conductors from the generator step-up transformer high-voltage terminals to the substation/switchyard bus. These conductors are not considered transmission Lines, so the "Line" equipment type designation would not be appropriate for these.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Portland General Electric Company	No	1) The fields listed in Attachment 1 are sufficient. However, the quarterly reporting requirement is buried under the Compliance Monitoring Process, but should be a clear separate requirement for the registered entities under the standard. 2) The reporting requirement R2 of UVLS standard PRC-022 is slated to be retired per Project 2013-02, but 4.2.2 specifically excludes UVLS from this standard. This could result in UVLS misoperations not being reported.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
New York Power Authority	No	Need to explain the relevance of the TADS and GADS data to the calculation of the

Organization	Yes or No	Question 5 Comment
		metric.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Exelon Corp.	No	1) o The list is good for a 50,000 foot level view of analysis results. Protection Systems are too complex and dissimilar to obtain meaningful analyses at the level of the Attachment. Also, understand that the purpose of Attachment 1 is not to trouble-shoot misoperation, only to provide a database of types of misoperations as a performance indicator. 2) o Item C1.4 - Additional Compliance Information requires the quarterly Misoperation Data - Attachment 1 to be submitted within two calendar months following the end of each calendar quarter. This does not allow for the time limits specified in requirements R1, R2, and R3 for investigating, identifying and creating a CAP for the associated misoperation.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
MISO	No	It is unclear whether or not Attachment 1 is part of the standard that must be complied with. The SDT should clarify whether the misoperation information listed in Attachment 1 must be provided as specified. If that is the expectation, then the data requirements must be stipulated as a Requirement. As an Attachment without associated Requirements, we interpret that data submission as not mandatory.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Texas Reliability Entity	No	(1) Is Attachment 1 considered to be part of the Standard? If so, then future modifications to Attachment 1 would have to go through through the SDT process

Organization	Yes or No	Question 5 Comment
		and would entail extensive time and effort to make. (2) Under current practice, in many cases there is insufficient detail provided by the entities involved in a Misoperation to understand the root cause. There has been some discussion with the Protection System Misoperation Task Force (PSMTF) that additional data would be helpful in categorizing misoperations. In particular, it would be helpful to add subcategories below the misoperation general cause codes (i.e. Incorrect settings/logic design could have subcategories such as modeling errors, calculation errors, etc.). (3) The Periodic Data Submittal requirements and the template should be flexible enough to permit Regional Entities to collect additional information which may be beyond the scope of the PRC-004 Standard, if deemed necessary based on regional needs. For example, in ERCOT, the current regional rules for misoperation reporting also include failure to reclose, reporting the generator trips < 100kV, sudden pressure relay misoperations, SPS misoperations based on a regional definition, etc. These are included in the current template to streamline the reporting process for the Registered Entities, rather than requiring multiple reports. Since this information is outside the PRC-004 applicability, it is removed from the quarterly Misoperation reports by Texas RE before data is submitted to NERC. The previous draft of PRC-004-3 had flexibility in the periodic data submission language to allow this ("using the format specified by the ERO"), but that language was removed in the current draft.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
The United Illuminating Company	No	UI does not agree with including any of the reporting process in the PRC-004 standard or its attachments. The information to report does not require Ballot Body Approval initially or each time a field is to be modified.
Response: Thank you for your comment.		

Organization	Yes or No	Question 5 Comment
Please read the Summary Consideration for Question 5.		
Modesto Irrigation District	No	Resolution Status has too many options. Keep it simple. Suggest 1) Evaluation underway, 2) Evaluation Completed, Remediation activity begun, 3) Remediation activity complete.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Liberty Electric Power LLC	No	Limit resolution status to "work in progress" and "complete".Forms are too complex, with many elements not used by generator operators (example:TADS), or not known by GOPs ("Other BED elements", etc.)
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Cogentrix Energy, LLC	No	1) There are too many classification choices in the “Resolution Status” field of the report form. An equally effective status report can be delivered using three choices:1) Analysis In Progress [Still Under Investigation]; 2) Analysis Completed - Corrective Action Plan Pending; 3) Corrective Action Completed [Investigation Complete, Corrective Action Complete] 2) The form for GOs should differ from that for TOs, for the following reasons:a. GOs are not in a position to respond to the last item on p.1, “Additional BES Interruptions.” We know only what happens in our plants, not repercussions on the grid. 3) b. The “slow trip” entries in the “Misoperations Category” do not apply for the majority of Misoperations reported by GOs. The presence of such categories in the draft standard appears to derive from the belief that millisecond-resolution records of Misoperations are always available from DME; but, when this equipment is present at generation plants, it is installed only at the GSU and (if

Organization	Yes or No	Question 5 Comment
		the GO is the owner) the yard breaker - that is, on high-side equipment. The DME is consequently not expected to yield any useful information for Faults occurring at the generator or other low-side components. Notes should be added to PRC-004-3 and the Application Guidelines to the effect that DME downloading and speed-of-response analysis pertain at generation Facilities only when DME is present and only to incoming Faults from the grid. 4) Further, the current draft standard does not dictate whether quarterly reporting to the CEA is required and enforceable, as it is currently (the term "will" as opposed to "shall"). 5) Additionally, there is no reference to reporting in a manner outlined by the CEA/RRO. The use of a common "form" is needed to achieve the usefulness and effectiveness of these data submittals.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Independent Electricity System Operator	No	We have a difficulty determining whether or not Attachment 1 is part of the standard and therefore must be complied with. As presented, Attachment 1 is referenced under Section C 1.4, Additional Compliance Information. Section C specifies the compliance monitoring/audit evidence requirements and which are not regarded as a standard Requirement that must be complied with to achieve a reliability outcome. Further, as with the list of evidence presented in CANs and RSAWs, the information/record presented in these documents are examples of acceptable evidence. Deviations from the specified information are acceptable for so long as the information provided can demonstrate compliance with the Requirements. If the SDT holds the position that the misoperation information listed in Attachment 1 must be provided as specified, then the data requirements must be stipulated in a Requirement. Having data requirement not stipulated in a Requirement will render that data submission not mandatory.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Sacramento Municipal Utility District	No	We feel the data is appropriate. 1) However, we feel the trending data is more appropriately collected thru NERC's Section 1600 process. As no clear information is provided how the data is to be utilized we don't believe it should identified nor included as a compliance component. Further, national trending may inappropriate skew information that may be region specific diluting the results. 2) Also, including the attachment in the standard would require a drafting team for any changes for requested data.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
CenterPoint Energy	No	(a) CenterPoint Energy is concerned that the 'Slow Trip - During Fault' misoperation example that is used in Attachment 1 may be misleading and could result in incorrect reporting; therefore, we recommend developing another example, such as, an 'Unnecessary Trip - During Fault' misoperation which is a more commonplace. Although there may not enough information included for the proposed example to know for certain, CenterPoint Energy suspects that there may have been a non-communications-based, directional time-overcurrent relay, which was part of the Protection System, which ultimately tripped the transmission line. Such a scenario may not be a reportable misoperation, as the proposed Misoperation definition for 'Slow Trip - During Fault' includes the following clarification: "Delayed Fault clearing associated with an installed high-speed protection scheme is a Misoperation if the high-speed performance is required to meet the performance requirements of the TPL standards or by coordination requirements with other Protection Systems." In other words, the following is stated in the Guidelines and Technical Basis: "Delayed

Organization	Yes or No	Question 5 Comment
		fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high speed performance is not required by planning studies associated with the TPL standards or by coordination requirements with other Protection Systems." (b) The 'Equipment Voltage (kV)' field in Attachment A states: "Enter the system voltage of the BES equipment associated with the Protection System that Misoperated. For transformers, use the high side voltage." While using the high side voltage could be appropriate for generator step-up transformers, CenterPoint Energy recommends the system voltage for autotransformers be based on the low side voltage, in order to provide consistency with other NERC criteria, including Reliability Standards, such as, PRC-023 Transmission Relay Loadability.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Ameren Services	No	We suggest to (1) change 'Time Zone' Field Value to prevailing time (e.g. CPT for Central Prevailing Time) to make reporting more efficient. (2) split Incorrect Setting/Logic/Design Errors into three separate categories to improve the usefulness of the metrics regarding Protection System performance. (3) split Communication Failure into two separate categories, one for 'Carrier' and one for 'non-Carrier' to improve the usefulness of the metrics regarding Protection System performance. (4) eliminate the TADS and GADS data submittals. Instead request the total number of operations at each Equipment Voltage level because this is a more effective means of gathering the information for all Protection System operations. (5) Align Attachment 1 with the present reporting template to ease burden on entities. (6) We also believe that (a) Declarations should be included in the Attachment 1

Organization	Yes or No	Question 5 Comment
		reporting template and (7) (b) The reporting template should be contrived so that it automatically documents and thus provides much of the evidence required by the standard.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Essential Power, LLC	No	1) There are too many classification choices in the "Resolution Status" field of the report form. An equally effective status report can be delivered using three choices:1) Analysis In Progress [Still Under Investigation]; 2) Analysis Completed - Corrective Action Plan Pending; 3) Corrective Action Completed [Investigation Complete, Corrective Action Complete] 2) The form for GOs should differ from that for TOs, for the following reasons:a. GOs are not in a position to respond to the last item on p.1, "Additional BES Interruptions." We know only what happens in our plants, not repercussions on the grid.b. The "slow trip" entries in the "Misoperations Category" do not apply for the majority of Misoperations reported by GOs. The presence of such categories in the draft standard appears to derive from the belief that millisecond-resolution records of Misoperations are always available from DME; but, when this equipment is present at generation plants, it is installed only at the GSU and (if the GO is the owner) the yard breaker - that is, on high-side equipment. The DME is consequently not expected to yield any useful information for Faults occurring at the generator or other low-side components. Notes should be added to PRC-004-3 and the Application Guidelines to the effect that DME downloading and speed-of-response analysis pertain at generation Facilities only when DME is present and only to incoming Faults from the grid. 3) Further, the current draft standard does not dictate whether quarterly reporting to the CEA is required and enforceable, as it is currently (the term "will" as opposed to "shall"). 4) Additionally, there is no reference to reporting in a manner outlined by the

Organization	Yes or No	Question 5 Comment
		CEA/RRO. The use of a common "form" is needed to achieve the usefulness and effectiveness of these data submittals.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Western Small Entity Comment Group	Yes	But we do not like the new format. Having each event on an individual line made the information easier and quicker to find. The new format has each event spread over many rows and columns.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Project 2010-05.1	Yes	FirstEnergy (FE) agrees with the concept that this data is necessary for analysis, however, by listing the Attachment within the Compliance section would lead one to believe that Attachment 1 was part of the standard, when in actuality it is not.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
American Electric Power	Yes	We encourage the SDT to ensure this form is consistent with SPCS form.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP agrees that the data listing is generally consistent with the existing process.
Response: Thank you for your comment.		

Organization	Yes or No	Question 5 Comment
Please read the Summary Consideration for Question 5.		
PSEG	Yes	Metrics can be developed, but the team should describe what metrics it envisions and how those metric will be used.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
NextEra Energy Inc.	Yes	NextEra has no issue with the information requested or the format, but requests that NERC and the regions all use the same form for the collection of misoperation data.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Associated Electric Cooperative Inc - JRO00088	Yes	
Pepco Holdings Inc & Affiliates	Yes	
Souhwest Power Pool Reliability Standards Development Team	Yes	
Detroit Edison	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 5 Comment
Southwest Power Pool Regional Entity	Yes	
Operational Compliance	Yes	
TVA Transmission Operations and Maintenance	Yes	
Western Area Power Administration	Yes	
Okanogan PUD	Yes	
National Grid	Yes	
Manitoba Hydro	Yes	
Tri-State G&T	Yes	
NorthWestern Energy	Yes	
Clark Public Utilities	Yes	
Utility System Efficiencies, Inc.	Yes	
Idaho Power Co.	Yes	
LCRA Transmission Services Corporation	Yes	
Dairyland Power Cooperative	Yes	

Organization	Yes or No	Question 5 Comment
Orange and Rockland Utilities	Yes	
Public Service Company of New Mexico	Yes	
City of Austin dba Austin Energy	Yes	
US Bureau of Reclamation	Yes	
Los Angeles Department of Water and Power	Yes	
Consumers Energy	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
Oncor Electric Delivery	Yes	
Kansas City Power & Light	Yes	
City of Jacksonville Beach, FL dba/ Beaches Energy Services		(No Comment.)

6. **The team has included VRFs, VSLs, and Time Horizons with this posting. Do you agree with the assignments that have been made? If not, please provide specific reasons why not and alternative recommendations and justifications.**

Summary Consideration:

A large percentage of the entities that commented stated that the 10-day intervals between severity levels for Requirements R1, R2, or R3 were too short. The drafting team used the NERC guideline: "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its "Violation Severity Level Guidelines." However, based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.

Several commenters questioned the 'High' VRF for Requirement R4 because Part 4.2 appeared to be administrative. The drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The VRF was not changed.

Several commenters noted that the VSLs for Requirements R2, R3, and R4 were not always consistent with the language in the requirements and the drafting team corrected these inconsistencies.

A few commenters suggested that the VSLs for Requirement R1 should be based on multiple operations or a percentage of operations missed rather than the amount of time by which they were missed. The drafting team responded that: "Pursuant to Guideline 4 in FERC's Order on Violation Severity Levels document, "Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations."

A couple of commenters were concerned that the requirements didn't consider the varying level of impact that different types of Misoperations can have on the BES. The drafting team responded that the NERC Sanction Guidelines allow NERC or the regional entity to 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 when evaluating a violation.

Organization	Yes or No	Question 6 Comment
Northeast Power Coordinating Council	No	There should be no respopnse to this question. I can't deselect either "Yes" or "No".
Response: Thank you for your comment.		
Western Small Entity Comment Group	No	Violation risk factors should be entity specific based on the equipment owned and their place in the system and not on the requirement alone.
Response: Thank you for your comment. **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." As the description indicates, each VRF is associated with a requirement and not on the equipment owned and their place in the system.**		
Associated Electric Cooperative Inc - JRO00088	No	On Page 11, the Severe VSL column's phrase containing "OR The responsible entity completed its review of a Protection System operation that operated one of its interrupting devices in 120 calendar days and determined the operation was a Misoperation and failed to designate the operation as a Misoperation in accordance with Requirement R1, Part 1.2. ":Append: "and the Responsible entity failed to perform the subsequent R1 Part 1.3 as well."Rationale: We fail to see the reason for severity of impact otherwise.
Response: Thank you for your comment. **The drafting team revised Requirement R1 and the associated VSLs.**		
Pepco Holdings Inc & Affiliates	No	The language in the VSL's for Requirement R2 should be changed to match the language in the Requirement. The present language uses the phrase "...following the completion of the investigation or receiving notification." That phrase should be eliminated and instead the phrase "...after the cause of the misoperation has been

Organization	Yes or No	Question 6 Comment
		identified" should be inserted.
Response: Thank you for your comment. **The drafting team modified each VSL to end with the phrase "following the identification of the cause of the Misoperation."**		
Souhwest Power Pool Reliability Standards Development Team	No	Most entities will be compliant or not. 1. We don't agree that the severity level needs to be raised based on being an additional 10 days late. We would suggest revisiting this section and possibly make the interval 30 days in between a severity increase. 2. The high VRF in requirement R4 applies to both 4.1 and 4.2. We agree that 4.1 should be a high VRF since it has to do with the actual implementation. On the other hand 4.2 seems to be purely administrative dealing only with maintaining implementation records. We don't agree that this is a high VRF. In fact we question if it should even be included in this requirement and should fall under the Paragraph 81 project that is ongoing.
Response: Thank you for your comments. **1. The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.** **2. Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised.**		
Tacoma Power	No	Under the Lower and Moderate VSLs for R3, the description ends with "...following the associated interrupting device operation " Under the High and Severe VSLs, the description ends with "...following the completion of the investigation." Was this

Organization	Yes or No	Question 6 Comment
		difference intended? It seems that there should be consistency.
Response: Thank you for your comment. **The drafting team modified the High and Severe VSLs to be consistent with the Lower and Moderate VSLs.**		
El Paso Electric	No	Based on the NERC's definition of High - Violation Risk Factor, EPE believes the assignment of High Risk to R4 does not seem to be warranted. R4 combines the implementing and documentation of any corrective actions in connection with a misoperation, and does not impact the reliability of the BES. EPE believes a separation of the implementing process and documentation requirements may provide a solution.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised.**		
Santee Cooper	No	As stated in Question 3, we do not feel the timetables involved are needed for ensuring operations and misoperations are handled appropriately. That being said, for R1 and R3, 30 days is a quick change from Lower to Severe. Suggest making the change for R1 and R3 should be proportionate to R2 (about 50%).
Response: Thank you for your comment. **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its "Violation Severity Level Guidelines." Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.**		

Organization	Yes or No	Question 6 Comment
Dominion	No	a). For R1 and R3 the escalation from Lower to Severe VSL in just 30 days is too short. Please make them more consistent with the requirement duration. As a comparison R2 escalates in 30 days, which is 50% of the time limit. We recommend keeping the 50% consistent for escalation to Severe with a limit of 210 days for R1 and 270 days for R3. b). By having specific 60 and 120 day requirements, this brings additional violation complexity to the process and is unessary. As stated previously, use same approach as COM 003 and eliminate the daily requirements. c). VSLs will need to address when a Misoperation is caused by an entity having no equipment operations where initial analysis is by first party and remainder of requirements apply to second party. (See comments to Question 4)
Response: Thank you for your comments. **a). The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.** **b). Thank you for your comment.** **c). The drafting team believes the revised requirements, measures and VSLs adequately address your concern.**		
Luminant	No	Change accordingly to the response to Q2 and Q3.
Response: Thank you for your comment. **The VSLs were adjusted to be congruent with the revised requirements.**		

Organization	Yes or No	Question 6 Comment
SERC Protection and Control Subcommittee (PCS)	No	While the SERC PCS does not see the need for timetables (see comment under #3), if they are put in place, we offer the following recommendations: 1) For R1 and R3 the escalation from Lower to Severe VSL in just 30 days is too short. Please make them more consistent with the requirement duration. As a comparison, R2 escalates in 30 days, which is 50% of the time limit. We recommend keeping the 50% consistent for escalation to Severe with a limit of 210 days for R1 and 270 days for R3. 2) R2 VRF measures duration from 'completion of the investigation or receiving notification' but R2 itself measures from 'identifying the cause(s) of each Misoperation'. Please change the VRF language to match R2 itself. The only notification we see is in R1, and it is inappropriate to measure CAP development duration from the time a component is only suspected.
Response: Thank you for your comments. **1) The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.** **2) Based on comments, the drafting team modified the Requirement R2 VSLs to be measured from the date of "identifying the cause(s) of each Misoperation."**		
ACES Power Marketing Standards Collaborators	No	(1) We agree with the classification of the VRFs. (2) The time horizons for R2, R3, and R4 are Long-term Planning, which is a planning horizon of one year or longer. There is a gap in the time horizons - the 180 day mark is longer than seasonal but shorter than 1 year. We recommend classifying these standards as Operations Planning, which would be consistent with R1.

Organization	Yes or No	Question 6 Comment
		(3) The violation severity level for R1 increases based on arbitrary timelines. It is conceivable that an entity could identify and review a Misoperation on day 150 (which would be a severe VSL) and complete the CAP 20 days after, which would still be within the 180 day timeframe (established by R1 with R2). The VSLs do not reflect the spirit of the standard and need to be revised with reasonable timelines. If R1 was not complete within 180 days, then that would be more justifiable for a high VSL and if an entity did not do anything that would be a reasonable justification for severe. (4) Also in R1 VSL, the second paragraph in the Lower section is almost identical to the second paragraph in severe, which is confusing and could lead to inconsistent application. We recommend revising the R1 VSLs for clarity and would like the SDT to consider creating VSLs that determine the severity level if R1 and R2 are not completed in a certain period of time. (5) Our concerns with the R2 VSL are similar to paragraph (3) above. It is conceivable that an entity could identify and review a Misoperation on day 30 and complete the CAP 70 days after (which would be a severe VSL), and would still be well within the total 180 day timeframe (established by R1 with R2). The VSLs do not reflect the spirit of the standard and need to be revised with reasonable timelines. If R1 was not complete within 180 days, then that would be more justifiable for a high VSL and not doing anything would be a reasonable justification for severe.

Response: Thank you for your comments.

(1) Thank you for your support.

(2) Requirements R2, R3, and R4 have dual Time Horizons of Operations Planning and Long-Term Planning. The drafting team recognizes that there is a gap in the VSL time frames, but addressing the timeframe gap is outside the scope of the drafting team.

(3) The drafting team believes the timeframes in the requirements are not arbitrary, but were established considering the impacts of seasonal weather-related operations. The timeframe associated with each VSL pertains to the individual requirement, and do not relate to the actions of other requirements and their associated VSLs.

Organization	Yes or No	Question 6 Comment
(4) The drafting team believes the two VSLs are sufficiently different such that no inconsistent application will occur. **(5) The timeframe associated with each VSL pertains to the individual requirement, and does not relate to the actions of other requirements and their associated VSLs.**		
Bonneville Power Administration	No	The time limits between the different VSL's are arbitrary. For example, if an operation is analyzed within 120 days there is no violation, but if it is analyzed after more than 150 days, only 25% later, it is a severe violation. BPA believes it would be more appropriate to have only a single violation severity level of low or moderate after the 120 day deadline.
Response: Thank you for your comments. **The NERC Violation Severity Guidelines do not allow for a single VSL that is Lower or Moderate; from page 2 "Requirements: If the requirement is a "pass or fail" type requirement or when any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement, then the single VSL must be "Severe". (This is not the same as saying that the requirement is really important and any noncompliance would have an adverse reliability impact – the impact to reliability should be addressed through the VRF, not the VSL.)"** **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.**		
GTC	No	GTC does not agree with VSL R4 Lower VSL - Concerned statement "records were incomplete" is an opened quantifier and is not auditable, leaves to much room for interpretation for auditor. Request statement like "did not contain signed-off evidence of any revision(s) or completion of defined actionable items defined in document".

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised.**		
ISO/RTO Standards Review Committee	No	As a general comment on VRFs and VSLs, there does not seem to be a correlation between how a lack of address of a particular protection system operation is tied to how severe an impact it had or may have on the reliability of the BES. For example, an operation of an auxililary tripping relay for tap configuration substation does not have the same BES impact as a bus differential relay scheme in a full ring configuration substation.
Response: Thank you for your comment. **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."** **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.**		
JEA	No	1. This increases from low to severe by 10 day increments so if it takes you 5 months instead of 4 you are at a severe VSL. 2. Also missing just one review results in a severe level. Also not notifying an adjacent entity that you think they may have contributed to the problem is a severe violation - the severity should be based on the number of occurances. We think that 30 day increments are appropriate and severity levels should also be

Organization	Yes or No	Question 6 Comment
		based on the percentage of missed reviews such as 1%, 2%, 5%.
Response: Thank you for your comments. 1. **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.** 2. **Pursuant to Guideline 4 in FERC's Order on Violation Severity Levels document, "Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the NERC Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations."**		
TVA Transmission Operations and Maintenance	No	The limits and time horizons are too restrictive and do not take into account if an entity is making a good faith attempt to investigate a misoperation and for reasons outside of its control, cannot meet the arbitrary numbers in this draft. There needs to be exemptions made for the safe operation of the transmission system to override the limits. Maybe some sort of deferral process with proposed dates to replace the time horizons when system conditions cannot support the necessary work required to investigate and correct.
Response: Thank you for your comments. **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.**		

Organization	Yes or No	Question 6 Comment
Please note that the timeframes for the Corrective Action Plan or action plan are for development only and not for implementation.		
Nebraska Public Power District	No	1. Other comments and concerns stated for R1.1 would need to be addressed and modified in the VSLs. 2. The severe violation for failure to notifiy and provide requested investigative information should be removed. This will be difficult to audit and has a subjective nature. It also puts a burden on the sending utitilty where all aspects are not under their control especially if the receiver does not want to cooperate.
Response: Thank you for your comments. **1. The VSLs were adjusted to be congruent with the revised requirements.** **2. The drafting team believes that the VSLs for Requirement 1, Part 1.1 regarding the notification to the other entity and the response to the other entity are appropriate. No change was made based on this comment.**		
PacifiCorp	No	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 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.
Response: Thank you for your comment. **The drafting team used the NERC-recommended “Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL.**		

Organization	Yes or No	Question 6 Comment
To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.		
Western Area Power Administration	No	The metrics seem arbitrary and not linked to possible risk to the BES.
Response: Thank you for your comment. **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."** **However, the NERC Sanction Guidelines states 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 the NERC Sanction Guidelines address your comment.**		
Southern Company	No	a)VSLsfor the draft R1 and R2 should change based on the new time frame suggested in our response to Q2 and Q3. For the CAP development and documentation, keep only the "failed to develop..." as a VSL. b) The VSL shown for R3 reveals that R3 is not needed - the development and documentation of the CAP is the subject of the drafted R2, and the implementation of a CAP is the subject of the drafted R4. c) The severe VSL for R3 incorrectly lists implementation of the CAP as a measure - implementation of the CAP is the subject of the draft Requirement 4.â€‚â€‚ d) We suggest that the Severe VSL for R4 be the only VSL for that requirement.

Organization	Yes or No	Question 6 Comment
		e) The VRF for R4 is too high. It should match the other requirements - if the CAP is not implemented, there is no additional risk than if a Protection System operation is not reviewed. f) A new requirement for reporting to the RE should carry a low VRF.
Response: Thank you for your comment. **a) The VSLs were adjusted to be congruent with the revised requirements. The drafting team believes that a time frame for development of the Corrective Action Plan or action plan is appropriate to include in the VSLs.** **b) The drafting team disagrees. Requirement R3 is associated with an "action plan" that is required when a specific cause of the Misoperation is not discovered and not based on a Corrective Action Plan as defined in the NERC Glossary of Terms.** **c) Based on your comment, the drafting team removed the implementation component of the action plan from the Severe VSL for Requirement R3.** **d) Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised.** **e) 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."** **However, the NERC Sanction Guidelines states 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 the NERC Sanction Guidelines address your comment.** **f) The reporting obligations have been removed from the standard..**		
Okanogan PUD	No	In the VSL for R4 this is listed as a High Severity. We feel that small entities which are

Organization	Yes or No	Question 6 Comment
		on a 6 year audit cycle could have issues with document retention. Small entities 6 year entities do not have the resources to have the backup systems that larger entities. Also 6 year entities do not have the space and budget to ensure all documents are retained.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised. The difference in audit cycles for different sized entities is outside the scope of the drafting team.**		
ITC	No	1. The interval between severity levels should be 30 days instead of 10 days. 2. For the lower severity level associated with R4, the standard of 'incomplete records' is subjective unless M4 is revised.
Response: Thank you for your comments. **1. The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.** **2. Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised.**		
seattle city light	No	1. For R1, R2 and R3, SCL does not believe it is appropriate to increase the violation severity level based on the number of days beyond the required completion date. A company could have a great process and record of analyzing and correcting misoperations and receive a severe violation for a clerical error. Any potential violations in this area related to documentation and/or timing may fall into the "Find,

Organization	Yes or No	Question 6 Comment
		Fix, and Track" category or non-zero-defect treatment, and the VRF and VSL levels ought to be set in order to allow for the FFT process to apply. 2. It would be more appropriate to issue a lower VSL for a single instance of missing the required completion date or lacking documentation for a single event. A moderate or high VSL should be issued for missing multiple completion dates or lacking documentation in several areas. A severe VSL should be issued for not having a program or any evidence of achieving the requirement.
Response: Thank you for your comment. 1. **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its "Violation Severity Level Guidelines." Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.** 2. **Pursuant to Guideline 4 in FERC's Order on Violation Severity Levels document, "Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the NERC Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations."**		
Cleco Corporation	No	It seems to us the SDT spends too much time on the VRFs and VSLs. An Entity is either compliant or not and verifying whether you are within so many days seems perculiar. 1. Why was ten days choosen and not 30 or 45 days? 2. The high VRF in requirement R4 applies to both 4.1 and 4.2. We agree that 4.1 should be a high VRF since it has to do with the actual implementation. On the other hand 4.2 seems to be purely administrative dealing only with maintaining implementation records. We don't agree that this is a high VRF. In fact we question if it should even be included in this requirement and should fall under the Paragraph

Organization	Yes or No	Question 6 Comment
		81 project that is ongoing.

Response: Thank you for your comments.

1. **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.**
2. **Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised.**

Organization	Yes or No	Question 6 Comment
Wisconsin Electric	No	We suggest that the Time Horizon for all four Requirements should be the same, "Operations Planning, Long-Term Planning". R1 is presently listed as Operations Assessment, Operations Planning.

Response: Thank you for your comment.

The drafting team believes depending on the impact of the operation, this requirement may fall under the Operations Assessment time horizon and as such, no change was made to the standard.

Organization	Yes or No	Question 6 Comment
Manitoba Hydro	No	Many of the requirements in this standard appear to be administrative or documentation based. It is therefore surprising to us that the VRFs and VSLs would be so high. As we understood it, NERC would like to eliminate documentation-based requirements. Was that not the purpose of Project 2013-02 Paragraph 81? For documentation-based requirements, the VSLs appear to have very little leeway. 1. For example, in R1 if an entity is 20 days late the VSL jumps to High. This seems disproportionate in comparison to the insignificant reliability impact that delaying the review by 20 days will have on the BES. An entity should be late by significantly more time to warrant going up to a High or Severe VSL.

Organization	Yes or No	Question 6 Comment
		2. In terms of the VRFs, we do not agree that structured misoperation reporting will reduce misoperations and therefore feel that the VRFs should be lowered from Medium (R1, R2, R3) and High (R4) to Low and Medium. 3. VSLs - R2 - The time frames should run from the 'identification of the cause(s) of each Misoperation' rather than completion of the investigation or receiving notification to be consistent with the requirement language. 4. VSLs - R3 - High VSL and Severe VSL - the timeframes should run from the 'associated interrupting device operation' not the completion of the investigation to be consistent with the requirement language. 5. Severe VSL - the word 'in' is missing from the first paragraph in describing more than 210 calendar days. 'Implement' should be removed from the second paragraph as this is not required in the language of the requirement; the 'ed' should be removed from documented.

Response: Thank you for your comments.

1. **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.**
2. **The reporting obligations have been removed from the standard and no changes were made to the Violation Risk Factors.**
3. **Based on comments, the drafting team modified the Requirement R2 VSLs to be measured from the date of "identifying the cause(s) of each Misoperation."**
4. **The drafting team modified the High and Severe VSLs to be consistent with the Lower and Moderate VSLs in Requirement R3.**
5. **The drafting team made the suggested changes.**

Organization	Yes or No	Question 6 Comment
American Electric Power	No	1. The R1 VSL's should use percentages to determine the severity level. As written, a utility performing 99% of the identification, review, notification, designation and documentation correctly would receive a severe violation. 2. In the R4 VSL's, "The responsible entity failed to maintain records of a CAP or action plan" should be moved from severe to medium. The penalty for failing to document should be less than the penalty for failing to implement.
Response: Thank you for your comments. **1. Pursuant to Guideline 4 in FERC's Order on Violation Severity Levels document, "Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the NERC Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations."** **2. Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised.**		
Portland General Electric Company	No	Severe VSLs should not be applied for lateness, only for failure to perform the required activity.
Response: Thank you for your comment. **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.**		
LCRA Transmission Services Corporation	No	1. For R1, R2 and R3, we do not believe it is appropriate to increase the violation severity level based on the number of days beyond the required completion date. A company could have a great process and record of analyzing and correcting

Organization	Yes or No	Question 6 Comment
		misoperations and receive a severe violation for a clerical error. Any potential violations in this area related to documentation and/or timing may fall into the "Find, Fix, and Track" category, and the VRF and VSL levels ought to be set in order to allow for the FFT process to apply. It would be more appropriate to issue a lower VSL for a single instance of missing the required completion date or lacking documentation for a single event. A moderate or high VSL should be issued for missing multiple completion dates or lacking documentation in several areas. A severe VSL should be issued for not having a program or any evidence of achieving the requirement. We have no suggested change for R4.
Response: Thank you for your comment. **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.**		
MISO	No	As a general comment on VRFs and VSLs, there does not seem to be a correlation between how a lack of address of a particular protection system operation is tied to how severe an impact it had or may have on the reliability of the BES.
Response: Thank you for your comment. **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."** **However, the NERC Sanction Guidelines states 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**		

Organization	Yes or No	Question 6 Comment
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 the NERC Sanction Guidelines address your comment.		
Modesto Irrigation District	No	VSL levels should comport with the amount of errors/missed completions discovered, not time delay for a single missed completion.
Response: Thank you for your comment. **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.**		
Liberty Electric Power LLC	No	Suggest removing R4 lower - too subjective.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised.**		
Cogentrix Energy, LLC	No	Better clarity for the lower VSL associated with R4 should be provided. The term "incomplete" is too ambiguous. The current language leaves determination of "completeness" of documentation up to the auditor.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised.**		

Organization	Yes or No	Question 6 Comment
Independent Electricity System Operator	No	We agree with the VRFs, VSLs and Time Horizons for R1, R2 and R3 but do not agree with the VRF and VSL for R4.We fully endorse the concept that a CAP needs to be implemented to ensure correct operations of the protective relay in question. However, not complying with R1 or R2 will result in not having a CAP to begin with. For this reason, we are unable to support a resulting requirement (R4) having a higher VRF than the prerequisite requirement at the front end. 1. We therefore suggest to change the VRF for R4 to a MEDIUM. 2. We also disagree with "The responsible entity failed to maintain records of a CAP or action plan." in R4 to be assigned a SEVERE VSL. The main intent of R4 is to implement the CAP, whose non-compliance warrants a SEVERE VSL. However, having implemented the CAP meets the main intent of R4 and hence missing the needed documentation does not contribute to adverse reliability impact. We therefore suggest the VSL for Part 4.2 to be a LOWER, or a MEDIUM at most.

Response: Thank you for your comment.

1. **The drafting team disagrees and declines to make the suggested change. 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."**

   However, the NERC Sanction Guidelines states 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 the NERC Sanction Guidelines address your comment.

2. **Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects**

Organization	Yes or No	Question 6 Comment
from the requirement. The associated VSLs were also revised.		
NextEra Energy Inc.	No	NextEra disagrees with the approach taken in the VSLs that provides a range of days to determine the severity of the violation. The importance of investing and implementing a correct action plan for a misoperation varies on the type of misoperation and the need or not to implement a corrective action to address reliability. NextEra favors all aspects of the Reliability Standards moving to a risk, results based approach, including VSLs. Thus, the VSLs should be re-drafted to measure whether an entity has timely implemented a corrective action plan for misoperations that pose a risk to reliability, with consideration of the level of the risk and other factors such as complexity of the issue, costs and outages, etc.
Response: Thank you for your comment. **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.**		
Ameren Services	No	(1) For R1 and R3 the escalation from Lower to Severe VSL in just 30 days is too short. We suggest that the SDT make them more consistent with the requirement duration. As a comparison R2 escalates in 30 days, which is 50% of the time limit. We recommend keeping the 50% consistent for escalation to Severe with a limit of 210 days for R1 and 270 days for R3. (2) R2 VRF measures duration from 'completion of the investigation or receiving notification' but R2 itself measures from 'identifying the cause(s) of each Misoperation'. We suggest t that the SDT change the VRF language to match R2 itself. The only notification we see is in R1, and it is inappropriate to measure CAP development duration from the time a component is only suspected.

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comments. **(1) The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.** **(2) Based on comments, the drafting team modified Requirement R2 VSLs to be measured from the date of "identifying the cause(s) of each Misoperation."**		
Essential Power, LLC	No	Better clarity for the lower VSL associated with R4 should be provided. The term "incomplete" is too ambiguous. The current language leaves determination of "completeness" of documentation up to the auditor.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised.**		
PSEG		We did not focus on the VRFs and VSLs and have no comments
Response: Thank you.		
City of Jacksonville Beach, FL dba/ Beaches Energy Services		(No Comment.)
Response: Thank you.		
Exelon Corp.	Yes	o Please confirm that the Application Guidelines material will be kept with the standard. One example of why this is important is so that the statement regarding

Organization	Yes or No	Question 6 Comment
		natural disasters and extenuating circumstances is included. Specifically, the Application Guidelines currently contain the following: “In the event of a natural disaster, note that the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.”
Response: Thank you for your comment. **This material will be retained in the Guidelines and Technical Basis section of the standard.**		
Texas Reliability Entity	Yes	We generally agree, however the Severe VSL for R1 includes “and failed to notify and provide requested investigative information” but it doesn’t address the situation where the entity provided notification, but failed to provide “requested investigative information.” Also, the R1 VSL is overly complicated, perhaps showing that there are too many different elements in R1.
Response: Thank you for your comment. **Based on the comment, the drafting team modified the Severe VSL for Requirement R1 to state “…and failed to notify or provide requested investigative information…”**		
Detroit Edison	Yes	
Colorado Springs Utilities	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
Duke Energy	Yes	
Project 2010-05.1	Yes	

Organization	Yes or No	Question 6 Comment
Southwest Power Pool Regional Entity	Yes	
Operational Compliance	Yes	
National Grid	Yes	
Tri-State G&T	Yes	
NorthWestern Energy	Yes	
Clark Public Utilities	Yes	
Utility System Efficiencies, Inc.	Yes	
Idaho Power Co.	Yes	
Ingleside Cogeneration LP	Yes	
New York Power Authority	Yes	
Dairyland Power Cooperative	Yes	
Orange and Rockland Utilities	Yes	
Public Service Company of New Mexico	Yes	
City of Austin dba Austin Energy	Yes	

Organization	Yes or No	Question 6 Comment
The United Illuminating Company	Yes	
US Bureau of Reclamation	Yes	
Los Angeles Department of Water and Power	Yes	
Consumers Energy	Yes	
Sacramento Municipal Utility District	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
Oncor Electric Delivery	Yes	

7. **The team has included Measures and Data Retention with this posting. Do you agree with the assignments that have been made? If not, please provide specific suggestions for improvement.**

Summary Consideration:

Several commenters suggested that Measure 1 should align more with the reference information contained in the Guidelines and Technical Basis section of the standard. The drafting team responded by modifying Measure M1 for clarity and affirming that the Guidelines and Technical Basis section of the standard is not mandatory or enforceable and serves only as additional reference information.

Some commenters were confused by the boiler plate language in the Evidence Retention section while other commenters wanted the evidence retention periods shortened. The drafting team responded by removing the boiler plate sentence from the standard (first paragraph of C 1.2 Evidence Retention) that appeared to conflict with the "since the last audit" language in the second paragraph. The drafting team also reiterated that the evidence retention period should begin with the completion of the last audit period.

Some commenters in general believed Measures M1 and M4 were too restrictive. The drafting team revised the measures such that they list the minimum evidence required (if any) and provide examples of other acceptable evidence.

A few commenters requested more clarity regarding evidence retention for circumstances that crossed audit periods. The drafting team responded by adding the following language to Section C 1.2 "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 interrupting device operation occurred prior to the current audit period."

Organization	Yes or No	Question 7 Comment
Western Small Entity Comment Group	No	We disagree with M1 for the same reason we disagree with R1 in Q2 above.
Response: Thank you for your comment. **The drafting team believes that reviewing every operation is the only way to be sure that Misoperations are not missed. The extent of the review should be relevant to the operation.**		

Organization	Yes or No	Question 7 Comment
Pepco Holdings Inc & Affiliates	No	1. The proposed data retention requirements seem reasonable. However, the following comments are offered in order to improve clarity and avoid confusion regarding the wording of Measures M1 and M2. 1) The wording on Measure M1 should be revised to substitute Requirement numbers in place of Part numbers. For example, it should read “shall have evidence for Requirement R1.1 that....” Instead of “shall have evidence for Part 1.1 that....” 2. In addition, because the list of evidence is not all inclusive it should end with the phrase “or other records”. For example, “but is not limited to dated lists, logs, databases, or other records, that document...” 3. Measurement M2 requires evidence which must include a “dated CAP”. It is unclear what a “dated CAP” means. Does it refer to the date the CAP was developed; the date the CAP is proposed to be completed by; or both? This needs to be clarified.
Response: Thank you for your comments. **1. The drafting team is using the current NERC format, there are Requirements and Parts.** **2. The drafting team included the lead in statement “that may include, but is not limited to” to allow for inclusion of other types of acceptable evidence.** **3. The drafting team intends this to be the date the CAP development was formalized.**		
Tacoma Power	No	1. Referring to M4, change “...that must include...” to “...that may include...” 2. Referring to Evidence Retention, the first paragraph appears to conflict with the second. In the first paragraph, the draft standard says, “For instances where the evidence retention period specified below is shorter than the time since the last audit...” However, in the second paragraph, the draft standard says “...shall keep data or evidence to show compliance with...since the last audit...” Given the language in the second paragraph, how can the evidence retention period be less

Organization	Yes or No	Question 7 Comment
		than the time since the last audit, as the first paragraph suggests may be possible?
Response: Thank you for your comments. 1. **The drafting team revised Measure M4 such that it lists the minimum evidence required and provides examples of other acceptable evidence.** 2. **The drafting team removed the boiler plate sentence from the standard that appeared to conflict with the "since the last audit" language in the second paragraph.**		
Dominion	No	(If requirements change, measures need to change also. See comments to Question 4)
Response: Thank you for your comment.		
Luminant	No	1. Measure M1 should not be written to include "all interrupting device operations must be logged". Luminant recommends that the measure for Part 1.1 be revised from "each interrupting device" to "each applicable interrupting device". 2. M1 measures for part 1.2 and 1.3 would be "Acceptable evidence for Part 1.2 may include, but is not limited to, electronic or written documents that indicate the owner of was notified of the event associated with the operation. Acceptable evidence for Part 1.3 may include, but is not limited to, a copy of a dated investigation report or documented findings for Misoperation."
Response: Thank you for your comments. 1. **The drafting team made the suggested change to Measure M1.** 2. **The drafting team modified Measure M1.**		
ACES Power Marketing Standards Collaborators	No	The SDT referenced NERC Rules of Procedure, Appendix 4C (CMEP), Section 3.1.4.2 Period Covered for compliance data retention to begin with the day after the prior Compliance Audit and ending with the End Date for the Compliance Audit. However,

Organization	Yes or No	Question 7 Comment
		the SDT did not include the final two sentences in Section 3.1.4.2, which states: "However, if a Reliability Standard specifies a document retention period that does not cover the entire period described above, the Registered Entity will not be found in noncompliance solely on the basis of the lack of specific information that has rightfully not been retained based on the retention period specified in the Reliability Standard. However, in such cases, the Compliance Enforcement Authority will require the Registered Entity to demonstrate compliance through other means." Six years is excessive to maintain records for Corrective Action Plans. The SDT is within the bounds of the NERC Rules of Procedure to shorten that amount of time. We recommend three years for data retention for Correction Action Plans.
Response: Thank you for your comment. **The drafting team believes the evidence retention period should begin with the completion of the last audit period. The drafting team removed the boiler plate sentence from the standard that appeared to conflict with the "since the last audit" language in the second paragraph.**		
PPL Corporation NERC Registered Affiliates	No	M1 generically references lists, logs and databases, while the Application Guidelines cite much more specific evidence (sequence of events, relay targets, summary of DME records). By including different wording for a requirement in two separate documents, it creates ambiguity as to what is required by the Reliability Standard to demonstrate compliance. These two documents should be in seamless agreement.
Response: Thank you for your comment. **The drafting team modified Measure M1 for clarity. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable and serves only as additional reference information.**		
Project 2010-05.1	No	For M4, FE would prefer to rewrite to the following: "Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R4 that may include, but is not limited to, "

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comment. **The drafting team revised Measure M4 such that it lists the minimum evidence required and provides examples of other acceptable evidence.**		
Bonneville Power Administration	No	The language of M4 is that the evidence for R4 must include a list of five items, and the last item in the list is linked with “or”. It is not clear if the evidence must include all five items in the list, or if only one item is required. Please clarify.
Response: Thank you for your comment. **The drafting team revised Measure M4 such that it lists the minimum evidence required and provides examples of other acceptable evidence.**		
Nebraska Public Power District	No	As mentioned above there are concerns with requirement R1.1 and M1. See comments for question 5.
Response: Thank you for your comment. **See our response for question 5.**		
Southern Company	No	1. The first paragraph of compliance Section 1.2 Evidence Retention is not needed and should be removed. (It is redundant to the second paragraph.) 2. M1 generically references lists, logs and databases, while the Application Guidelines cite much more specific evidence (sequence of events, relay targets, summary of DME records). These two documents should be in seamless agreement; we need to know specifically what will and will not be required when our records are audited, as opposed to being told when it’s too late to do anything about it that our lists, logs etc do not constitute sufficient evidence.
Response: Thank you for your comments.		

Organization	Yes or No	Question 7 Comment
1. The drafting team removed the boiler plate sentence from the standard that appeared to conflict with the "since the last audit" language in the second paragraph. **2. The drafting team modified Measure M1 for clarity. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable and serves only as additional reference information.**		
Okanogan PUD	No	As stated in Questin 6, we feel that a 6 year data retention policy could prove onerous to small entities. We would prefer a much smaller data retention policy, such as 3 years (which would be the retetion period of large entities.
Response: Thank you for your comment. **The drafting team believes the evidence retention period should begin with the completion of the last audit period.**		
ITC	No	M1, M2, M3 seem sufficient. M4 is unclear. Please clarify. The following would be clearer. M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R4 that must include dated electronic or hard copy records that document the implementation, completion and any revision to each CAP or action plan. Acceptable records include, but are not limited to:- Dated work management program records- Dated Work orders- Dated Maintenance Records
Response: Thank you for your comment. **The drafting team revised Measure M4 such that it lists the minimum evidence required and provides examples of other acceptable evidence.**		
Wisconsin Electric	No	In M1, the acceptable evidence for Parts 1.1 and 1.2 should also include "electronic or hard copy records", as it does for the notification required by Part 1.1.
Response: Thank you for your comment. **The drafting team modified Measure M1 as requested.**		

Organization	Yes or No	Question 7 Comment
Manitoba Hydro	No	1. In R1 and its associated measure, the measure implies that more work needs to be done in terms of the level of review that the requirement itself. The requirement is vague and could be interpreted differently by different people. This requirement and measure should both be re-worded to be more clear and consistent. (See related comments under Question 2.) 2. Since for each Protection System operation, either R2 or R3 would apply, the words “As Applicable” should be added to these measures. 3. Also, in M1 the wording “Part 1.1” is used. This should say “Requirement R1.1”.
Response: Thank you for your comments. **1. The drafting team revised Requirement R1 and Measure M1. Please review the new requirement and measure.** **2. The lead in statement in each requirement gives the conditions when that requirement is applicable. The measure is associated with each requirement so if the requirement is not applicable then the measure is not applicable.** **3. The drafting team is using the current NERC format, there are Requirements and Parts.**		
Exelon Corp.	No	1. Measure M4 - change “must include” to “could include”. So the new wording is as follows: “Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R4 that could include, but is not limited to, dated electronic or hard copy records which document the implementation of each CAP and action plan, completion of actions and revisions for each CAP or action plan; dated work management program records, dated work orders, or dated maintenance records.”
Response: Thank you for your comment. **The drafting team revised Measure M4 such that it lists the minimum evidence required and provides examples of other acceptable evidence.**		

Organization	Yes or No	Question 7 Comment
City of Austin dba Austin Energy	No	The phrase "must include" in measure 4 should likely be "may include."
Response: Thank you for your comment. **The drafting team revised Measure M4 such that it lists the minimum evidence required and provides examples of other acceptable evidence.**		
PSEG	No	We have proposed alternative Measures in #2 and #3 above and in #9 below. The Data Retention language is acceptable.
Response: Thank you for your comment. **See our responses to the associated questions.**		
Liberty Electric Power LLC	No	Disagree with the requirement for "each interrupting device activation" list - some activations are normal shutdown activations.
Response: Thank you for your comment. **The existing phrase "caused by a Protection System operation" excludes operation of devices initiated by operators. The use of reverse power relays for generator shutdown is excluded from the operations review. See the Guidelines and Technical Basis section of the standard referencing category (6) of the definition of Misoperation.**		
Cogentrix Energy, LLC	No	M1 generically references lists, logs and databases, while the Application Guidelines cite much more specific evidence (sequence of events, relay targets, summary of DME records). These two documents should be in seamless agreement; we need to know specifically what will and will not be required when our records are audited, as opposed to being told when it's too late to do anything about it that our lists, logs etc do not constitute sufficient evidence.
Response: Thank you for your comment.		

Organization	Yes or No	Question 7 Comment
The drafting team modified Measure M1 for clarity. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable and serves only as additional reference information.		
City of Tallahassee	No	I do not see any reference to Data Retention.
Response: Thank you for your comment. **See Section C 1.2 of the draft standard.**		
NextEra Energy Inc.	No	NextEra disagrees with the data retention periods, given that it is also submitting quarterly reports. Specifically, from a monitoring and compliance perspective, there should be no need to maintain all data in between audits if the entity is also submitting quarterly reports. Instead, the entity should only be required to maintain one years worth of data. Since, at any time, a regional entity can via a spot check or a compliance audit review data to access compliance, it seems redundant and onerous to require that the entity stockpile three to six years of data related to misoperatrions depending on their audit cycle. Moreover, such a data retention requirement seems to be inconsistent with NERC's movement to a risk and results based approach rather than a review of past evidence and a check list approach to compliance. Accordingly, NextEra requests that the data retention be reduced to only one year.
Response: Thank you for your comment. **The reporting obligations have been removed from the standard. The drafting team believes the evidence retention period should begin with the completion of the last audit period.**		
Essential Power, LLC	No	M1 generically references lists, logs and databases, while the Application Guidelines cite much more specific evidence (sequence of events, relay targets, summary of DME records). These two documents should be in seamless agreement; we need to know specifically what will and will not be required when our records are audited, as opposed to being told when it's too late to do anything about it that our lists, logs etc

Organization	Yes or No	Question 7 Comment
		do not constitute sufficient evidence.
Response: Thank you for your comment. **The drafting team modified Measure M1 for clarity. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable and serves only as additional reference information.**		
City of Jacksonville Beach, FL dba/ Beaches Energy Services		(No Comment.)
Response: Thank you.		
SERC Protection and Control Subcommittee (PCS)	Yes	1) Please clarify that an entity is to retain evidence for all Misoperations with an open investigation, action plan, or CAP since the last audit even if the interrupting device operation occurred before the last audit.
Response: Thank you for your comment. **The drafting team added the following language to Section C 1.2 to address your concern "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 interrupting device operation occurred prior to the current audit period."**		
Southwest Power Pool Regional Entity	Yes	In Section C 1.2, the following sentence does not seem to make sense because there are no shorter time periods specified: "For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit."
Response: Thank you for your comment. **The drafting team believes the evidence retention period should begin with the completion of the last audit period. The drafting team removed the boiler plate sentence from the standard that appeared to conflict with the "since the last audit" language in the**		

Organization	Yes or No	Question 7 Comment
second paragraph.		
Sacramento Municipal Utility District	Yes	SMUD also encourages the development and concurrent posting of the Reliability Standard Audit Worksheet with the next standard posting.
Response: Thank you for your comment. **Your comment was forwarded to NERC staff.**		
Ameren Services	Yes	We suggest that the SDT clarify that an entity is to retain evidence for all Misoperations with an open investigation, action plan, or CAP since the last audit even if the interrupting device operation occurred before the last audit.
Response: Thank you for your comment. **The drafting team added the following language to Section C 1.2 to address your concern "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 interrupting device operation occurred prior to the current audit period."**		
Northeast Power Coordinating Council	Yes	
Associated Electric Cooperative Inc - JRO00088	Yes	
Souhwest Power Pool Reliability Standards Development Team	Yes	
Detroit Edison	Yes	
Santee Cooper	Yes	

Organization	Yes or No	Question 7 Comment
Colorado Springs Utilities	Yes	
Duke Energy	Yes	
GTC	Yes	
Operational Compliance	Yes	
TVA Transmission Operations and Maintenance	Yes	
PacifiCorp	Yes	
Western Area Power Administration	Yes	
National Grid	Yes	
seattle city light	Yes	
Cleco Corporation	Yes	
Tri-State G&T	Yes	
NorthWestern Energy	Yes	
Clark Public Utilities	Yes	
American Electric Power	Yes	
Utility System Efficiencies, Inc.	Yes	

Organization	Yes or No	Question 7 Comment
Idaho Power Co.	Yes	
Portland General Electric Company	Yes	
LCRA Transmission Services Corporation	Yes	
Ingleside Cogeneration LP	Yes	
New York Power Authority	Yes	
Dairyland Power Cooperative	Yes	
Orange and Rockland Utilities	Yes	
Public Service Company of New Mexico	Yes	
The United Illuminating Company	Yes	
Modesto Irrigation District	Yes	
US Bureau of Reclamation	Yes	
Los Angeles Department of Water and Power	Yes	
Consumers Energy	Yes	

Organization	Yes or No	Question 7 Comment
Independent Electricity System Operator	Yes	
Oncor Electric Delivery	Yes	
Kansas City Power & Light	Yes	

8. **The team has included an Implementation Plan with this posting. Do you agree with the changes? If not, please provide specific suggestions for improvement.**

Summary Consideration:

Numerous commenters pointed out that the Implementation Plan did not reflect the twelve month implementation period established with the July posting. The drafting team modified the effective date to be "twelve months beyond the date that this standard is approved..."

Numerous commenters questioned how Protection System operations, Misoperations, CAPs, and reporting requirements will be transitioned from PRC-004-2a to PRC-004-3. The drafting team responded that the Implementation Plan provides entities 12 months to transition to the new requirements and compliance to PRC-004-3 is not required prior to the effective date of PRC-004-3. The reporting obligations have been removed from the standard, and the drafting team modified the Implementation Plan to distinguish between Protection System operations that occur before and after the effective date of the new standard.

Organization	Yes or No	Question 8 Comment
Pepco Holdings Inc & Affiliates	No	We agree with the timetable associated with the implementation of the new definition of a misoperation and for implementing the requirements in PRC-004-3. However, the following changes in the commentary included in the Implementation Plan should be made: 1) Re-word the definition of misoperation in accordance with the comments that we provided in Question 1 in this form. 2) Modify the list of "Facilities not included" to add Underfrequency Load Shedding (UFLS). 3) Modify the list of "Facilities not included" to expand on the Control section as follows: "Control (e.g. controlled shutdown of generators, capacitor bank switching, and SVC, FACTS and HVDC control system actions. Also see Guidelines and Technical Basis section for detailed examples)" Although the list is not intended to be all inclusive, mentioning the most frequently used control systems negates the need to

Organization	Yes or No	Question 8 Comment
		have to refer to the additional Guidelines and Technical Basis for most applications.
Response: Thank you for your comments. 1. **See our response to your comment in Question 1. The Implementation Plan will reflect any changes to definitions or the standard.** 2. **Misoperation of Underfrequency Load shedding is not handled by any other NERC standard so therefore must remain part of this standard. The drafting team clarified this by adding clause 4.2.2 to Applicability Section 4.2 of the draft standard.** 3. **The drafting team modified clause 4.2.4 of Applicability Section 4.2 to state: "Non-protective functions that may be imbedded within a Protection System are excluded."**		
Dominion	No	1.) Must include a specific plan of transitioning open investigations or CAPs to new standard requirements and reporting requirements. 2.) Specifically state when all other requirements are effective.
Response: Thank you for your comments. 1. **The Implementation Plan provides entities 12 months to transition to the new requirements and compliance to PRC-004-3 is not required prior to the effective date of PRC-004-3. The reporting obligations have been removed from the standard, and the drafting team modified the Implementation Plan to distinguish between Protection System operations that occur before and after the effective date of the new standard.** 2. **The section "Implementation Plan for Requirements R1, R2, R3 and R4" states the effective date for each requirement.**		
Operational Compliance	No	Establishing the "most stringent" standard between WECC & NERC requirements will be difficult and time-consuming. Regional standards should fully complement and enhance NERC Standards. To that end, the NERC standard PRC-004 should be written such that the related WECC standards CAN fully complement and enhance it.
Response: Thank you for your comment. **Regional standards must be more stringent than the Continent-wide NERC standard. The drafting team included the following in**		

Organization	Yes or No	Question 8 Comment
the Background section of the draft standard: "Note that the WECC Regional Reliability Standard PRC-004-WECC-1 relates to the reporting of Misoperations for a limited set of WECC Paths and Remedial Action Schemes. In those cases where PRC-004-WECC-1 overlaps with the Continent-wide standard, entities are expected to comply with the more stringent standard."		
American Electric Power	No	AEP does not have problem with the implementation plan; however, the implementation duration of six months is not consistent with the response in the SDT's Consideration of Comments which indicate it is 12 months.
Response: Thank you for your comment. **The effective date in the Implementation Plan has been changed to "twelve months beyond the date that PRC-004-3 is approved..." as previously stated in the last Consideration of Comments.**		
Exelon Corp.	No	o Implementation date: This standard is to go into effect on the first day of the first calendar quarter, 3 months after Board of Trustees adoption. This does not allow adequate time for the necessary programmatic and procedural changes required for a large organization. Suggest more time be allowed - such as one year after Board of Trustees adoption.
Response: Thank you for your comment. **The effective date in the Implementation Plan has been changed to "twelve months beyond the date that PRC-004-3 is approved..."**		
The United Illuminating Company	No	The implementation plan should recognize that the Requirements will be applied to the first protection system operation that occurs AFTER the effective dates. Any operations or misoperations or corrective action plans being implemented are not subject to this Standard.
Response: Thank you for your comment. **The Implementation Plan provides entities 12 months to transition to the new requirements and compliance to PRC-004-3 is not required prior to the effective date of PRC-004-3. The drafting team modified the Implementation Plan to distinguish between**		

Organization	Yes or No	Question 8 Comment
Protection System operations that occur before and after the effective date of the new standard.		
PSEG	Yes	No comments.
Ameren Services	Yes	(1) Are Misoperations with open CAP to be transitioned from PRC-004-2a to PRC-004-3 as Update Submittal Type once it becomes effective? (2) Six months after approval may be too short a time to modify processes and software to efficiently meet the PRC-004-3 requirements and supporting evidence.
Response: Thank you for your comments. **1. The Implementation Plan provides entities 12 months to transition to the new requirements and compliance to PRC-004-3 is not required prior to the effective date of PRC-004-3. The reporting obligations have been removed from the standard, and the drafting team modified the Implementation Plan to distinguish between Protection System operations that occur before and after the effective date of the new standard.** **2. The effective date in the Implementation Plan has been changed to "twelve months beyond the date that PRC-004-3 is approved..."**		
SERC Protection and Control Subcommittee (PCS)	Yes	Are Misoperations with open CAP to be transitioned from PRC-004-2a to PRC-004-3 as 'Update' Submittal Type once it becomes effective?
Response: Thank you for your comment. **The Implementation Plan provides entities 12 months to transition to the new requirements and compliance to PRC-004-3 is not required prior to the effective date of PRC-004-3. The reporting obligations have been removed from the standard, and the drafting team modified the Implementation Plan to distinguish between Protection System operations that occur before and after the effective date of the new standard.**		
ACES Power Marketing Standards Collaborators	Yes	1. Why is UFLS not excluded when UVLS is? 2. Also, are registered entities required to perform the 120-day assessment at least once before the enforceable date? Please refer to CAN-0012, which provides that if

Organization	Yes or No	Question 8 Comment
		the standard is silent to performing a periodic activity, the entity can perform the first activity after the enforceable date.
Response: Thank you for your comments. 1. **Misoperation of Underfrequency load shedding is not addressed by any other NERC standard so therefore must remain part of this standard. UVLS Misoperations are addressed in PRC-022-1.** 2. **Compliance to PRC-004-3 will not be required before the effective date of PRC-004-3.**		
Santee Cooper	Yes	Need to clarify how misoperations that are still not completed are going to be transitioned.
Response: Thank you for your comment. **The Implementation Plan provides entities 12 months to transition to the new requirements and compliance to PRC-004-3 is not required prior to the effective date of PRC-004-3. The reporting obligations have been removed from the standard, and the drafting team modified the Implementation Plan to distinguish between Protection System operations that occur before and after the effective date of the new standard.**		
City of Jacksonville Beach, FL dba/ Beaches Energy Services		(No Comment.)
Northeast Power Coordinating Council	Yes	
Western Small Entity Comment Group	Yes	
Associated Electric Cooperative Inc - JRO00088	Yes	

Organization	Yes or No	Question 8 Comment
Souhwest Power Pool Reliability Standards Development Team	Yes	
Detroit Edison	Yes	
Tacoma Power	Yes	
Luminant	Yes	
Colorado Springs Utilities	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
Duke Energy	Yes	
Project 2010-05.1	Yes	
Bonneville Power Administration	Yes	
GTC	Yes	
Southwest Power Pool Regional Entity	Yes	
TVA Transmission Operations and Maintenance	Yes	
Nebraska Public Power District	Yes	

Organization	Yes or No	Question 8 Comment
Western Area Power Administration	Yes	
Southern Company	Yes	
Okanogan PUD	Yes	
National Grid	Yes	
ITC	Yes	
seattle city light	Yes	
Cleco Corporation	Yes	
Wisconsin Electric	Yes	
Tri-State G&T	Yes	
NorthWestern Energy	Yes	
Clark Public Utilities	Yes	
Utility System Efficiencies, Inc.	Yes	
Idaho Power Co.	Yes	
Portland General Electric Company	Yes	
LCRA Transmission Services	Yes	

Organization	Yes or No	Question 8 Comment
Corporation		
Ingleside Cogeneration LP	Yes	
New York Power Authority	Yes	
Dairyland Power Cooperative	Yes	
Orange and Rockland Utilities	Yes	
Public Service Company of New Mexico	Yes	
City of Austin dba Austin Energy	Yes	
Modesto Irrigation District	Yes	
US Bureau of Reclamation	Yes	
Liberty Electric Power LLC	Yes	
Los Angeles Department of Water and Power	Yes	
Consumers Energy	Yes	
Cogentrix Energy, LLC	Yes	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 8 Comment
Sacramento Municipal Utility District	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
NextEra Energy Inc.	Yes	
Essential Power, LLC	Yes	
Oncor Electric Delivery	Yes	
Kansas City Power & Light	Yes	

9. **If you have any other comments on this Standard that you have not already provided in response to the prior questions, please provide them here.**

Summary Consideration:

Many commenters had questions surrounding the completion of a CAP when evaluating the possibility of a similar Misoperation at other locations. The drafting team responded with the following: "An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same cause from creating another misoperation and having an adverse effect on reliability. 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. The CAP is complete when the evaluation and all actions specified by the entity in the CAP are complete. The evaluation in Requirement R2 does not require prescribing actions at other locations. If the entity prescribes actions at other locations in its CAP then the CAP is not complete until all the specified actions are completed."

A few commenters had questions surrounding the time limits associated with the requirements. An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Guidelines and Technical Basis section of the draft standard has been revised to add clarity for the independent 120 and 60 day timeframes.

A few commenters had questions surrounding the time limits associated with CAP duration and completion. The drafting team responded with the following: Establishing fixed time limits for the completion of CAPs is impractical because of the wide spectrum of Misoperation causes and the variety of corrective actions. A schedule or timetable is required to be included in the CAP.

A few commenters questioned the difference between a CAP and an action plan. The drafting team explained that a CAP is developed when the cause of the Misoperation and corrective actions have been determined. In instances where the entity's initial investigations do not determine the cause of the Misoperation; the entity would develop an action plan to perform more in-depth investigations. If the investigation does not provide direction for identifying the cause, then pursuing further action is not warranted. In these cases, documenting the reasons is essential for justifying the close out of the Misoperation investigation process and for future reference.

Several commenters had concerns with the amount of administrative burden. To eliminate some of the administrative burden, the drafting team revised Requirement R4 and Measure M4 removing the revision tracking for a CAP or an action plan. The requirements

and associated documentation help ensure the responsible entities are diligent about Misoperation response, CAP creation and completion. Consequently, the drafting team does not believe this documentation detracts from the reliable operation of the BES.

Several commenters had concerns that the standard implied additional monitoring equipment must be installed. The drafting team responded with the following: The standard does not require any additional monitoring equipment to be installed. Each responsible entity must review each of its Protection System operations and determine whether the operation should be categorized as a Misoperation based on its available information. The entity will use whatever means at their disposal in order to determine whether the operation was correct or not which may include available Disturbance Monitoring Equipment.

Several commenters had concerns about the consistency of the Facilities section of the draft standard with regards to the Facilities Section of PRC-005-2, as well as the interpretation attached to the existing standard PRC-004-2a. In response, the drafting team revised the Facilities section by: 1) revising 4.2.1 to read: Protection Systems for BES Elements; 2) adding 4.2.2 which reads: Underfrequency Load Shedding (UFLS) that trips a BES Element; 3) restructuring 4.2.3 to read: Special Protection Systems (SPS), Remedial Action Schemes (RAS), and Undervoltage Load Shedding (UVLS) are excluded; and 4) revising 4.2.4 to read: Non-protective functions that may be imbedded within a Protection System are excluded.

Organization	Yes or No	Question 9 Comment
Cogentrix Energy, LLC		1. Compliance section C1.4 contains a requirement to report to the RE - this needs to be in the requirement section of the standard.
Response: Thank you for your response. **Please see the drafting team's decision surrounding 'reporting' in the Summary Consideration for Question 5 on Page 141 of this document.**		
Dominion		1. R2 introduces the idea of a CAP "that includes an evaluation of the CAP's applicability to the entity's Protections Systems at other locations". R4 states "maintain detailed implementation records of CAP including dated information surrounding any revision(s) and completion". With all this said, is the CAP complete once we evaluate "identify every location where a similar problem may exist" or is the CAP only complete when all locations are fixed? 2. There is no need to log revision(s) to the CAP. Having a current CAP available at

Organization	Yes or No	Question 9 Comment
		any point in time should be sufficient without tracking CAP changes. 3. In the Rationale for R4 it states “fully implemented”. We interpret this to mean fully evaluated and not fully fixed at all other locations?
Response: Thank you for your comment. 1 An evaluation of the CAP’s applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another misoperation and having an adverse effect on reliability. 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. The CAP is complete when the evaluation and all actions specified by the entity in the CAP are complete. 2 The drafting team revised Requirement R4 to eliminate the tracking aspects for CAP revisions. 3 ‘Fully implemented’ was intended to mean all steps of the CAP or action plan have been completed. The drafting team replaced the term ‘fully implemented’ with ‘completed.’ The evaluation in Requirement R2 does not require prescribing actions at other locations. If the entity prescribes actions at other locations in its CAP then the CAP is not complete until all the specified actions are complete.		
Texas Reliability Entity		(1) R2 assumes that one or more “Protection System component(s)” has previously been “identified”, but there is no preceding requirement that requires any such identification of components. R2 seems to infer that it is the owner of the component that caused the Misoperation who must act, but it is not expressly stated who is responsible for this requirement. (2) We agree with the approach of R2, however, we would suggest the following changes to wording to clarify this requirement by requiring certain elements in each Corrective Action Plan: R2. Within 60 calendar days of identifying the cause(s) of each Misoperation, each applicable Entity shall: o Develop and document a Corrective Action Plan (CAP) and work timetable to resolve the cause(s) of the Misoperation that includes the following: 1. Interim corrective actions (if any),

Organization	Yes or No	Question 9 Comment
		2. Final corrective actions, 3. An evaluation of the CAP's applicability to the entity's Protection Systems at other Facilities, 4. An evaluation of the CAP's applicability to Protection System component(s) owned by another Registered Entity (if applicable for the specific event),or o Explain in a declaration why corrective actions are either beyond the entity's control, applicable to another Registered Entity, or would reduce BES reliability. (3) In R4: Implementation of the CAP should include a time limit. We suggest re-wording R4.1 to say "Implement the CAP or action plan within 180 calendar days after developing the CAP or action plan, or per the CAP or action plan timetable, whichever is longer."

Response: Thank you for your comment.

1 **The drafting team has clarified Requirement R1 to show that the interrupting device owner will do the initial investigation and will contact other Protection System owners only if a correct operation cannot be determined. In this case, the investigative information is passed from the interrupting device owner to the other owners. The standard requires all owners to confirm whether their portions of the Protection System operated correctly or not within 120 days of the interrupting device operation. As stated in the Guidelines and Technical Basis section of the standard, the drafting team expects all owners to work jointly in making these determinations, freely sharing information with each other. Only the owner of a Protection System component that Misoperated is responsible for documenting the findings, developing a CAP or action plan.**

2 **The drafting team believes the existing wording of Requirement R2 provides adequate clarity and allows an entity to determine its appropriate response based on each individual event.**

3 **A part of each CAP or action plan is its timetable. It is the responsibility of each entity to follow the timetable once they have established it. The drafting team recognizes that during the implementation process it might be necessary to modify the original timetable and Requirement R4 allows for this. The 180 day criteria proposed would only impact a CAP or action plan with an implementation timetable of less than 180 days. If an entity discovers it is unable to meet the initial timetable they can modify their schedule to a date they can meet even if it exceeds the 180 days, making the proposed criteria unnecessary.**

Organization	Yes or No	Question 9 Comment
Ameren Services		(1) R2 states that the CAP applies to the identified Protection System component(s). But then goes on to say the CAP "includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations." It is unclear whether the entity is required to take corrective actions at those other locations in order to complete the CAP. Our reading and expectation is that the entity completes the CAP, when they complete the identified work at the location of this Misoperation. We would expect the entity to initiate a program to address the other locations over some reasonable time period. (2) We suggest that the SDT reword C.1.4 from "Each Transmission Owner, Generator Owner, and Distribution Provider that owns BES protection Systems will submit the data identified in PRC-004 - Attachment 1 to the CEA..." to "For Misoperation(s) caused by BES Protection System it owns, each Transmission Owner, Generator Owner, and Distribution Provider will submit the data identified in PRC-004 - Attachment 1 to the CEA..." This clarifies who is responsible for submitting when multiple entities are involved. (3) Attachment 1 "Action Plan/Declaration Development Date" example data should be "N/A". (4) Application Guidelines - Reporting section on page 20 states '...the fourth ranked initiating cause of BES outages not related to weather was "Failed Protection System Equipment." Given the high ranking of this metric, it is appropriate to collect data on Protection System Misoperations for analysis to drive improvements in Protection System reliability.' While this may be true in terms of number of events, is sensationalizes the Failed Protection System Equipment cause. In fact Failed Protection System Equipment is a very minor cause of unavailability. For full context, we suggest that the SDT also state: (a) the total number of non-weather related causes; b) the total number of causes; (c) its rank when BES outages related to weather are included; d) the top three non-weather related causes; (e) its rank in terms of BES unavailability; and f) the % of unavailability caused by Failed Protection

Organization	Yes or No	Question 9 Comment
		System Equipment. (5) M4 on page 8: We suggest t that the SDT replace 'must include' with 'may include' because some items do not apply to every CAP or action plan. Clearly the entity must document the implementation of each CAP and action plan, beyond that the range of documentation will vary depending on the situation. (6) Ameren agrees with and supports the comments of the SERC Protection & Control Subcommittee. (7) We suggest that the SDT augment the Application Guidelines Requirement 2 examples on page 17 to include "an evaluation of the CAP's applicability to the entity's Protection Systems at other locations." (8) We suggest that the SDT modify the Application Guidelines Requirement 1 wording on top of page 18 to make it clear that the suggested information should only be included as appropriate. The cause of some Misoperations is quite obvious and does not need copious tests, DFR records, and the like. For example, carrier switch may've been in the wrong position. (9) Editorial comments: a) p4 Applicability box - replace 'RMS' with 'RAS'; b) p5 Background 3rd line - Misoperation should be singular.

Response: Thank you for your comment.

1. **An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another misoperation and having an adverse effect on reliability. 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. The CAP is complete when the evaluation and all actions specified by the entity in the CAP are complete.**
2. **The reporting obligations have been removed from the standard. Please see the drafting team's decision surrounding 'reporting' in the Summary Consideration for Question 5 on Page 141 of this document.**
3. **The drafting team will forward these comments to the NERC Protection System Misoperations Task Force and the NERC System Protection and Control Subcommittee for content consideration.**

Organization	Yes or No	Question 9 Comment
4 Providing all the suggested detail would not improve the standard. The drafting team revised the text to minimize the emphasis. 5 The drafting team retained the 'must include' because it is the minimum evidence required for a CAP or action plan but modified the second sentence to state 'may also include.' 6 Please see the drafting team responses to the SERC PCS comments. 7 This type of evaluation would include items such as a relay firmware revision or an error found in an entity's "standard" protection logic that has been deployed at multiple locations. It is the responsibility of the Protection System owner to determine how wide spread the situation is and take the appropriate corrective actions. The drafting team has added example language to the Guidelines and Technical Basis section of the standard. 8 Text revised to read '…contains the sequence of events, relay targets and a summary and Disturbance Monitoring Equipment (DME) records as appropriate.' 9 The drafting team made the corrections.		
ACES Power Marketing Standards Collaborators		(1) There is ambiguity in R4, part 4.2, "maintaining detailed implementation records," which could be interpreted in different ways by auditors as to the degree of detail that is needed for implementation records. The measures give examples of acceptable methods to achieve compliance and therefore we recommend striking the word "detailed" from part 4.2. Further 4.2 is strictly a data retention requirement, which is administrative in nature and should be removed. This is the type of requirement that Paragraph 81 is currently in the process of retiring. (2) In part 4.2.3 of the applicability section, the SDT needs to emphasize that relay functions are not included in the definition of Protection Systems. By explicitly stating that certain non-protective functions that may be embedded within a Protection System are excluded, it could be interpreted that anything else that was not explicitly mentioned in the requirement could be included, such as sudden pressure relays. We recommend adding additional detail to this section for clarity. (3) Does the SDT intend to remove the old definition of Misoperations from the

Organization	Yes or No	Question 9 Comment
		background section? It does not need to remain as supplemental information with the passing of the new definition. We understand that certain aspects of the standard would be removed, such as the rationale boxes, but there is no mention that background section would be removed. (4) In the application guideline, Requirement R3 section, first paragraph first sentence - "If the Misoperation cause is not identified within 120 days, and reasonable investigative actions have not been exhausted, Protection System owners are expected to exercise due diligence in the development and implementation of an action plan for additional investigation." This sentence needs to clarify what reasonable means. It appears from this statement that if you did not exhaust all reasonable investigations, then you should continue additional investigations, but at that point, you would be in violation of R1. The SDT needs to consider rewording this sentence, possibly striking the underlined portion of the sentence. (5) In the application guideline, Requirement R4 section, second paragraph - this paragraph is discussing the goals of R3 and we recommend moving this paragraph to the R3 section. Thank you for the opportunity to comment.

Response: Thank you for your comment.

1. **Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement.**
2. **The drafting team revised the Facilities section of the standard based on yours and others comments.**
3. **The Background section is included in the final version of the approved standard.**
4. **Not determining a cause within 120 days would not be a violation of Requirement R1. If a cause has not been determined within the 120 days then Requirement R3 comes into play and the owner needs to develop an action plan or a declaration explaining why no further actions will be taken. The word "reasonable" is not in the requirement and is not mandatory or enforceable. The Guidelines and Technical Basis section of the standard provides information only.**
5. **The paragraph referenced in the comment discusses the action plan once it has been created in accordance with Requirement**

Organization	Yes or No	Question 9 Comment
R3. The bulk of the paragraph discusses Requirement R4 and calls for implementing the action plan and developing a CAP or declaration based on the determination of a cause via the action plan. The drafting team believes the paragraph is in the appropriate location.		
Independent Electricity System Operator		(1) There is no specific mention of UFLS and hence it is assumed that this standard applies to UFLS as well. However, there is no basis on why UFLS is included but UVLS is excluded in the Section A - 4.2 “Applicability”. There is also an apparent inconsistency between “Facilities not included” listed in section A.4.2.2 and definition related to under-voltage protection systems. The provision under 4.2 excludes the UVLS and capacitor switching from the applicability of the standard, and at the same time the definition (paragraph 2) gives as example of “other than fault”conditions the misoperation of under-voltage protection systems. (2) In the Background Section, a NOPR is mentioned but there is no specific information as to which NOPR it references. Need to add the relevant information. (3) The word “of” is missing from the bullet at the top of P.5 of the clean version.
Response: Thank you for your comment. **1 UFLS that trips a BES Element are covered by PRC-004-3. For clarity, the drafting team added the following in the included Facilities portion of the Applicability section 4.2.2 in the draft standard “Underfrequency Load Shedding (UFLS) that trips a BES Element”. The example of under-voltage does not refer to UVLS.** **2 Based on your comment, the drafting team removed the reference to the NOPR and replaced it with FERC Order No. 693.** **3 The drafting team corrected the error.**		
Pepco Holdings Inc & Affiliates		1) In Section 4.1.3 the wording should be changed to “Distribution Provider that owns a transmission Protection System”. This makes it consistent with the wording from previous versions of PRC-004, which recognized that it only applies to owners of Protection Systems that are applied to protect BES facilities. 2) A new Section 4.2.2.3 “Underfrequency Load Shedding (UFLS)” should be added

Organization	Yes or No	Question 9 Comment
		under the Applicability Section “Facilities not included.” Although UFLS schemes are Protection Systems covered under PRC-005 and are installed to preserve the BES from system underfrequency disturbances, they should not be included in this standard. Failing to specifically exclude them from this standard may lead to the assumption that they are by omission, included. Performance of UFLS schemes during system events are already covered in PRC-009, and as such do not need to be included in PRC-004-3. 3) Modify the list of “Facilities not included” to expand on the Control section as follows: “Control (e.g. controlled shutdown of generators, capacitor bank switching, and SVC, FACTS and HVDC control system actions. Also see Guidelines and Technical Basis section for detailed examples)” Although the list is not intended to be all inclusive, mentioning the most frequently used control systems negates the need to have to refer to the additional Guidelines and Technical Basis for most applications. 4) On page 6 of the Background section of PRC-004-3 there is a typographical error on the second bulleted item, “Analyze Misoperations of Protective Systems for Facilities ....” The word “of” is missing. 5) Also in the Background section the reason for the exclusion of UFLS should be addressed. 6) In Requirement R2 first bullet item remove the phrase “for the identified Protection System component(s)”. The term “component” should not be used, as it may lead to confusion. Individual Protection System component failures do not require a CAP unless the overall performance of the Composite Protection System for an Element was compromised. The bullet should instead read: “Develop and document a Corrective Action Plan (CAP) to address the identified misoperation that includes...”. 7) By NERC definition each CAP must contain a timeline for implementation. Requirement R4.1 requires you to complete the CAP. Does that mean that to be fully compliant the CAP must be completed within the proposed timeline stated in the

Organization	Yes or No	Question 9 Comment
		CAP? If so, there needs to be a mechanism to revise the proposed completion date when circumstances arise that prevent implementation in accordance with the originally proposed timeline (denial of facility outages, equipment delivery problems, major storm events, etc.) without being held non-compliant. 8) R4.2 “implies” that the CAP can be revised (presumably including the proposed completion date) as long as it is documented. If this is a correct interpretation of R4.2 then there is a mechanism to revise a CAP’s proposed completion date. On the other hand, this would allow the implementation of a CAP to be extended indefinitely by continuing to revise the proposed completion date. We doubt this is what the Standard Drafting Team intended. As such, the SDT may want to revisit the language dealing with revisions to a CAP.

Response: Thank you for your comment.

1 **The drafting team believes the Applicability section is clear and retains the intent of previous versions of PRC-004. In PRC-004-3, the functional entities are specified in Applicability section 4.1 and the Facilities are specified in Applicability section 4.2.**

2 **UFLS that trips a BES Element are covered by PRC-004-3. For clarity, the drafting team added the following in the included Facilities portion of the Applicability section 4.2.2 in the draft standard “Underfrequency Load Shedding (UFLS) that trips a BES Element”.**

3 **The drafting team revised the Applicability section and included the examples of non-protective functions in the Guidelines and Technical Basis section of the standard.**

4 **The drafting team corrected the error.**

5 **UFLS that trips a BES Element are covered by PRC-004-3.**

6 **Requirement R2 deals with an operation that has been determined to be a Misoperation and the cause was identified. This stage would not be reached unless the overall performance of the composite Protection System for an Element was compromised.**

7 **The drafting team agrees and revised Requirement R4.**

8 **The drafting team believes the Protection System owner should be allowed the freedom to draft and modify the CAP. The**

Organization	Yes or No	Question 9 Comment
Protection System owner has the option of writing a declaration explaining why no further action will be taken.		
Santee Cooper		1) R2 states that the CAP applies to the identified Protection System component(s). But then goes on to say the CAP "includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations." As it is presently handled, the entity can complete the CAP when the work at the place the misoperation took place is complete, and then the entity is responsible for its assessment/implementation at other locations (implementation of which may take a lot longer). However, the new standard needs to clearly state if this expectation is still the case, or if something different is now warranted. 2) Application Guidelines - Reporting section on page 20 states '...the fourth ranked initiating cause of BES outages not related to weather was "Failed Protection System Equipment." Given the high ranking of this metric, it is appropriate to collect data on Protection System Misoperations for analysis to drive improvements in Protection System reliability.' While this may be true in terms of number of events, it sensationalizes the Failed Protection System Equipment cause. In fact Failed Protection System Equipment is a very minor cause of unavailability. For full context, please also state: a) the total number of non-weather related causes; b) the top three non-weather related causes; and c) its rank in terms of BES unavailability. 3) All references to an investigation report should be changed to read "Misoperation investigation report" or "investigation report due to misoperations". Without this change it could be interpreted that all operations require an investigation report. This section is a very good description of what data may be used in an investigation report, but, for clarity of compliance purposes, it should be a little more defined as to which part of this is compliance-related and which parts are just informative. 4) Suggest having a more general statement such as "A misoperation investigation report should be of sufficient detail to either ascertain the cause of the misoperation or else describe the work performed/being performed to analyze the misoperation." For example, if you find a piece of equipment failed (powered down), a sequence of

Organization	Yes or No	Question 9 Comment
		events or DME records are not needed to figure out the cause, and so should not be required in the Misoperation investigation report. Along those same lines, we suggest adding a “may” and an “or” to the third sentence of page 18 “The initial evidence, which may also be documented separately, may contain the sequence of events, relay targets, and/or a summary of Disturbance Monitoring Equipment (DME) records.”

Response: Thank you for your comment.

1. **An evaluation of the CAP’s applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another misoperation and having an adverse effect on reliability. 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. The CAP is complete when the evaluation and all actions specified by the entity in the CAP are complete. The evaluation in Requirement R2 does not require prescribing actions at other locations. If the entity prescribes actions at other locations in its CAP then the CAP is not complete until all the specified actions are complete.**
2. **Providing all the suggested detail would not improve the standard. The drafting team revised the text to minimize the emphasis.**
3. **The drafting team agrees and made the suggested change.**
4. **Text revised to read ‘…contains the sequence of events, relay targets and a summary and Disturbance Monitoring Equipment (DME) records as appropriate.’**

Organization	Yes or No	Question 9 Comment
SERC Protection and Control Subcommittee (PCS)		1) R2 states that the CAP applies to the identified Protection System component(s). But then goes on to say the CAP “includes an evaluation of the CAP’s applicability to the entity’s Protection Systems at other locations.” It is unclear whether the entity is required to take corrective actions at those other locations in order to complete the CAP. Our reading and expectation is that the entity completes the CAP, when they complete the identified work at the location of this Misoperation. We would expect the entity to initiate a program to address the other locations over some reasonable time period.

Organization	Yes or No	Question 9 Comment
		2) Please reword C.1.4 from "Each Transmission Owner, Generator Owner, and Distribution Provider that owns BES protection Systems will submit the data identified in PRC-004 - Attachment 1 to the CEA..." to "For Misoperation(s) caused by BES Protection System it owns, each Transmission Owner, Generator Owner, and Distribution Provider will submit the data identified in PRC-004 - Attachment 1 to the CEA..." This clarifies who is responsible for submitting when multiple entities are involved. 3) Application Guidelines - Reporting section on page 20 states '...the fourth ranked initiating cause of BES outages not related to weather was "Failed Protection System Equipment." Given the high ranking of this metric, it is appropriate to collect data on Protection System Misoperations for analysis to drive improvements in Protection System reliability.' While this may be true in terms of number of events, it sensationalizes the Failed Protection System Equipment cause. In fact Failed Protection System Equipment is a very minor cause of unavailability. For full context, please also state: a) the total number of non-weather related causes; b) the top three non-weather related causes; and c) its rank in terms of BES unavailability. 4) A significant effort has been expended in developing the current PRC-004 misoperations template. The SERC PCS recommends that the SDT leverage this effort in consideration of misoperations reporting (Atta 1). 5) The SERC PCS recommends that the application guidelines be used for assessing misoperations and not for operations. 6) All references to an investigation report should be changed to read "Misoperation investigation report" or "investigation report due to misoperations". Without this change it could be interpreted that all operations require an investigation report. This section is a very good description of what data may be used in an investigation report, but, for clarity of compliance purposes, it should be a little more defined as to which part of this is compliance-related and which parts are just informative. (7) Suggest having a more general statement such as "A misoperation investigation

Organization	Yes or No	Question 9 Comment
		report should be of sufficient detail to either ascertain the cause of the misoperation or else describe the work performed/being performed to analyze the misoperation." For example, if you find a piece of equipment failed (powered down), a sequence of events or DME records are not needed to figure out the cause, and so should not be required in the Misoperation investigation report. Along those same lines, we suggest adding a "may" and an "or" to the third sentence of page 18 "The initial evidence, which may also be documented separately, may contain the sequence of events, relay targets, and/or a summary of Disturbance Monitoring Equipment (DME) records."

Response: Thank you for your comment.

1. **An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another misoperation and having an adverse effect on reliability. 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. The CAP is complete when the evaluation and all actions specified by the entity in the CAP are complete. The evaluation in Requirement R2 does not require prescribing actions at other locations. If the entity prescribes actions at other locations in its CAP then the CAP is not complete until all the specified actions are complete.**
2. **The reporting obligations have been removed from the standard. Please see the drafting team's decision surrounding 'reporting' in the Summary Consideration for Question 5 on Page 141 of this document.**
3. **Providing all the suggested detail would not improve the standard. The drafting team revised the text to minimize the emphasis.**
4. **The drafting team will forward these comments to the NERC Protection System Misoperations Task Force and the NERC System Protection and Control Subcommittee for content consideration.**
5. **There are examples in the Guidelines and Technical Basis section of the standard for accessing what is considered a misoperation and what is not considered a misoperation. The Guidelines and Technical Basis section of the standard provides information only.**
6. **The drafting team agrees and made the suggested change.**

Organization	Yes or No	Question 9 Comment
7 Text revised to read '…contains the sequence of events, relay targets and a summary and Disturbance Monitoring Equipment (DME) records as appropriate.'		
Xcel Energy		1) Regarding R1.1, it is not clear which entity would report the Misoperation, or be responsible for the remaining requirements. Would it be a joint responsibility? Please consider revising the requirement to indicate that the entities must agree on which one would handle the misoperation process, while the other would support as needed. 2) Consider including RAS/SPS, UVLS, UFLS under the applicability and eliminating the standards associated with misoperations on those specific types of protection systems.
Response: Thank you for your comment. (1) The drafting team has clarified Requirement R1 to show that the interrupting device owner will do the initial investigation and will contact other Protection System owners only if a correct operation cannot be determined. In this case, the investigative information is passed from the interrupting device owner to the other owners. The standard requires all owners to confirm whether their portions of the Protection System operated correctly or not within 120 days of the interrupting device operation. As stated in the Guidelines and Technical Basis section of the standard, the drafting team expects all owners to work jointly in making these determinations, freely sharing information with each other. Only the owner of a Protection System component that Misoperated is responsible for documenting the findings, developing a CAP or action plan. (2) RAS and SPS will be addressed in Project 2010-05.2 Phase 2 of Protection Systems: SPS and RAS. It is beyond the scope of this team to eliminate existing standards other than PRC-003-1 and PRC-004-2a. UFLS that trips a BES Element are covered by PRC-004-3.		
GTC		1) Why are UFLS schemes included in this standard but UVLS schemes are omitted? GTC recommends the addition UFLS be added to the list under Applicability section 4.2.2 (ex. 4.2.2.3). 2) Lastly, the overall tone of the document drives entities to focusing more labor and work on the documentation of an event than completion of a correctable action. In

Organization	Yes or No	Question 9 Comment
		addition, the dates for requirements and implementation seem to be defining how entities must perform work and does not give flexibility for entity to respond appropriately to problems. Possible to drive entities to provide a quick fix so they can close out documents instead of spending the appropriate time studying the event and define true root cause. Standard needs to measure performance by documenting events as misoperations with defining root cause. Should not cover expectations of an entity and drive them to a particular performance which may drastically change their business model and performance.

Response: Thank you for your comment.

(1) UFLS that trips a BES Element are covered by PRC-004-3. See the revised Facilities 4.2.2. The performance of UVLS schemes is covered by PRC-022-1.

(2) The standard provides flexibility to the Protection System owners to set the timetables within their CAPs or action plans. There are also provisions to revise the timetables if the situation warrants.

Organization	Yes or No	Question 9 Comment
Exelon Corp.		1) In the Introduction section, Applicability includes Distribution Provider. If this standard is for Protection Systems that are part of the BES, does a DP belong in the list of Functional Entities? 2) To what extent would an entity have to defend a determination that a system operation is considered to be a correct operation, if there is limited data to make the determination? This should be addressed in the Application Guide. 3) The Application Guidelines state that reverse power relay operations used for control of a generator (when a reverse power relay is used to trip a breaker during generator shutdown) are “not included in the definition of Misoperation and its operation would not be reviewed under this standard.” Since it can be debated whether a reverse power relay is used for control or generator protection, the Application Guidelines should remove the verbiage about the “control” aspect of this relay. The Application Guidelines should just state that “expected reverse power relay operations, such as those encountered when a generator comes off-line, would

Organization	Yes or No	Question 9 Comment
		not be required to be reviewed under this standard." This comment is not intended to remove the entire Application Guidelines discussion on control aspects of relays being excluded from needing a review under this standard. Rather, the intent of this comment is to revise the Application Guidelines so as to preclude any discussion over whether a reverse power relay is a control device or a protective device - and just list the exclusions for this relay, and any similar generator relays. 4) Exelon requests that the SDT clarify within the Standard that the interrupting device itself referenced in the Standard draft is also considered an element of the Bulk Electric System. Specifically, please clarify that a device on a radial line that does not affect the BES is excluded from this requirement. Suggest that this clarification be added to the Application Guidelines. 5) PRC-004 Requirement R1 requires that each Generator Owner identify and review each Protection System operation associated with an interrupting device operation. The SDT should re-evaluate this requirement as it implies that all generating facilities have established monitoring systems that will capture such events. Although some generating units do have existing monitoring systems (such as Disturbance Monitoring Equipment) not all generating units have such capability nor are they all required to install such monitoring equipment in accordance with existing FERC approved Standards. 6) Exelon agrees with the SDT revision to remove the requirement in R1 that an entity shall have and implement a "procedure" to identify and address all Protection System Misoperations within its system and that an existing Corrective Action Program will meet the intent of the Standard; however, the SDT response to the Exelon and Constellation comments submitted in the previous draft (Consideration of Comments in response to the 6/10/11 - 7/11/11 draft) is inaccurate and warrants clarification. The original Exelon comment was: "Nuclear GO/GOPs have an existing Corrective Action Program that is required by 10 CFR 50 Appendix B Criterion XVI (quoted below). This regulatory requirement and associated mandatory implementation of a Corrective Action Program by a Nuclear GO/GOP fully envelopes the intent of the

Organization	Yes or No	Question 9 Comment
		draft revision to PRC-004. An additional "procedure" to identify and address all Protection System Misoperations with set timelines and attributes is not necessary."XVI. Corrective Action Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management." The SDT response documented is as follows: "Thank you for your comments. These requirements cannot be used as a substitute for PRC-004-3 since they do not apply to Protection Systems on the electrical side of nuclear plants. In Order 706-B, FERC stated that much of a nuclear plant does not fall under the rules of the NRC. The NRC rules are applicable to the portions of the nuclear plant related to handling of radiological fuel, security and safety. NERC rules apply to the portion of the plant not under the rules of the NRC. BES electrical Protection Systems do not fall under the rules of the NRC." As a point of clarification, the SDT response that references Order 706-B indicates that BES electrical systems would not fall under NRC regulation. In summary, FERC Order 706-B "clarifies that the facilities within a nuclear generation plant in the United States that are not regulated by the U.S. Nuclear Regulatory Commission are subject to compliance with the eight mandatory 'CIP' Reliability Standards approved in Commission Order No. 706." In November 2010 FERC and the Nuclear Regulatory Commission (NRC) came to understand that because changes in electrical power output affect nuclear reactor core reactivity, NRC would have oversight of these "balance of plant" systems. FERC formalized this understanding in FERC Order issued March 10, 2011, Docket No. RM06-22-014, "...we find that the NRC's cyber security rule appears to cover all balance of plant, and no balance of plant at a U.S. nuclear power plant has been found to be subject to NERC's CIP Standards." It should be noted that the NRC required Corrective Action Program (regulatory requirement

Organization	Yes or No	Question 9 Comment
		information as documented above) applies to all systems, structures and components of a nuclear generating unit and therefore should be an acceptable method of complying with the revised Standard.

Response: Thank you for your comment.

1. **Distribution Providers that own Protection Systems that protect Facilities that are part of the BES are and should be included as applicable entities in this standard.**
2. **The entity will use whatever means at their disposal in order to determine whether the operation was correct or not which may include available DISTURBANCE MONITORING EQUIPMENT.**
3. **The section in the Guidelines and Technical Basis section of the standard concerning reverse power relays states "…the operation of the control component or the function when not providing protection is not included in the definition of Misoperation and its operation would not be reviewed under this standard." The drafting team declines to make the suggested change.**
4. **Protection Systems for Facilities that are part of the BES are included in the standard. The Applicability section, 4.2 Facilities 4.2.1 states this. The drafting team believes this adequately exempts non-BES equipment.**
5. **The standard does not require any additional monitoring equipment to be installed. Each Generator Owner must review each of its Protection System operations and determine whether the operation should be categorized as a Misoperation based on its available information. The entity will use whatever means at their disposal in order to determine whether the operation was correct or not which may include available DISTURBANCE MONITORING EQUIPMENT.**
6. **The drafting team continues to believe that our previous response is correct and the NERC standard does apply.**

Organization	Yes or No	Question 9 Comment
Southern Company		1) There needs to be some consistency between the proposed PRC-004, and PRC-005. How can one say a given Protection System needs to be maintained for the BES Reliability, but not necessarily operations analyzed. The Applicability of PRC-004: Protection Systems for Facilities that are part of the BES. The Applicability of PRC-005-2: 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.) 2) Please clarify the PRC-004 Applicability related to generators. It would indicate that

Organization	Yes or No	Question 9 Comment
		all protection systems at a generating plant that is part of the BES would be included. Is that the intent or is it only the Protection Systems associated with the protection of the Generator and/or step-up bank? 3) We suggest separating the Guideline and Technical Basis document from the remainder of the standard so that the document is less overbearing. â€‚â€‚ 4) As stated in the responses to several earlier questions, we recommend combining R2 with R1 and making the deadline for each the date of reporting to the RE, eliminating R3, renumbering R4 to R2, adding the revised version of Attachment 1 to the standard, and adding a new requirement which specifies the reporting responsibilities that are contained in the Compliance section C1.4. Based on our experience as a large utility in investigating, tracking, and reporting relay operations and misoperations, we believe these changes will be simpler, more efficient, more cost effective to implement while still achieving the desired goals.

Response: Thank you for your comments.

(1) The drafting team believes there is appropriate consistency between PRC-004-3 and PRC-005-2. The Protection Systems that are described in the 4.2 Facilities section of PRC-005-2 but are not covered in the PRC-004-3 Facilities description are excluded because either there is a plan to include them in the next phase of this project, they are already addressed by another standard, or they are automation and control functions that are not protection specific.

(2) Protection Systems that protect Facilities that are part of the BES and respond to electrical quantities such as overcurrent, loss of excitation, generator differential, step-up transformer differential and so forth. Trips such as turbine trips, fuel system trips, or boiler trips are not covered.

(3) The “Guidelines and Technical Basis” is reference information.

(4) The drafting team appreciates your suggestions and realizes there are other ways of structuring the standard; however, the posted version was developed and modified based on stakeholder comments. The drafting team declines to make the changes regarding the requirements. The reporting obligations have been removed from the standard. Please see the drafting team’s decision surrounding ‘reporting’ in the Summary Consideration for Question 5 on Page 141 of this document.

Organization	Yes or No	Question 9 Comment
City of Jacksonville Beach, FL dba/ Beaches Energy Services		1) Applicability of 4.2.1 “Protection Systems for Facilities that are part of the BES” is not consistent with the interpretation of PRC-004-1 Attachment 1 nor the applicability of PRC-005-2. We recommend using the FERC approved interpretation of PRC-004-1 Attachment 1. 2) R3 is not needed, is administrative in nature, and provides no reliability benefit. 3) R2 should be modified to be applicable only to misoperations where cause(s) were identified. 4) R4.2 is administrative in nature, is a Measure, not a requirement, and should be deleted.
Response: Thank you for your comments. **(1) The drafting team believes there is no conflict between PRC-004-3 and the interpretation of the phrase ‘transmission Protection System.’ The Applicability Section of PRC-004-3 includes: Protection Systems for Facilities that are part of the BES, and Requirement R1 stipulates: ‘…a BES interrupting device operation in its Facility caused by a Protection System operation…’ The drafting team believes these are consistent with the interpretation. The drafting team also believes there is appropriate consistency between PRC-004-3 and PRC-005-2. The Protection Systems that are described in the 4.2 Facilities section of PRC-005-2 but are not covered in the PRC-004-3 Facilities description are excluded because either there is a plan to include them in the next phase of this project, they are already addressed by another standard, or they are automation and control functions that are not protection specific.** **(2) The drafting team believes Requirement R3 is essential because it provides a path to resolution if a Misoperation is identified but no cause is determined within the first 120 days.** **(3) Requirement R2 states: Within 60 calendar days of identifying the cause of each Misoperation…** **(4) The drafting team agrees and revised Requirement R4 to eliminate the Parts.**		
Florida Municipal Power Agency		1) Applicability of 4.2.1 “Protection Systems for Facilities that are part of the BES” is not consistent with the interpretation of PRC-004-1 Attachment 1 nor the applicability of PRC-005-2. FMAP recommends using the FERC approved

Organization	Yes or No	Question 9 Comment
		interpretation of PRC-004-1 Attachment 1. 2) R3 is not needed, is administrative in nature, and provides no reliability benefit. 3) R2 should be modified to be applicable only to misoperations where cause(s) were identified. 4) R4.2 is administrative in nature, is a Measure, not a requirement, and should be deleted.
Response: Thank you for your comments. **(1) The drafting team believes there is no conflict between PRC-004-3 and the interpretation of the phrase 'transmission Protection System.' The Applicability Section of PRC-004-3 includes: Protection Systems for Facilities that are part of the BES, and Requirement R1 stipulates: '…a BES interrupting device operation in its Facility caused by a Protection System operation…' The drafting team believes these are consistent with the interpretation. The drafting team also believes there is appropriate consistency between PRC-004-3 and PRC-005-2. The Protection Systems that are described in the 4.2 Facilities section of PRC-005-2 but are not covered in the PRC-004-3 Facilities description are excluded because either there is a plan to include them in the next phase of this project, they are already addressed by another standard, or they are automation and control functions that are not protection specific.** **(2) The drafting team believes Requirement R3 is essential because it provides a path to resolution if a Misoperation is identified but no cause is determined within the first 120 days.** **(3) Requirement R2 states: Within 60 calendar days of identifying the cause of each Misoperation…** **(4) The drafting team agrees and revised Requirement R4 to eliminate the Parts.**		
Tampa Electric Company		1) Applicability of 4.2.1 "Protection Systems for Facilities that are part of the BES" is not consistent with the interpretation of PRC-004-1 Attachment 1 nor the applicability of PRC-005-2. TEC recommends using the FERC approved interpretation of PRC-004-1 Attachment 1. 2) R3 is not needed, is administrative in nature, and provides no reliability benefit. 3) R2 should be modified to be applicable only to misoperations where cause(s) were

Organization	Yes or No	Question 9 Comment
		identified. 4) R4.2 is administrative in nature, is a Measure, not a requirement, and should be deleted. 5) The big change that I see for us is significantly increased documentation. Currently all of our documentation is in a database including a brief description of the corrective action plan. It seems to satisfy the new standard we would need a separate CAP document to capture all of the additional info they are asking for, we may be able to link the CAP document to our database. The standard asks for documented proof that the work associated with the CAP was actually done (data from work management system, work order etc.). Presently we just log the completion date in our database we don't capture any proof that the work was done. Fortunately we typically only have a few misoperations per year so the volume of work will not be huge but it is just another ratcheting up of the documentation requirements. TEC doesn't see the increased documentation requirements doing anything to increase our reliability.

Response: Thank you for your comments.

(1) The drafting team believes there is no conflict between PRC-004-3 and the interpretation of the phrase 'transmission Protection System.' The Applicability Section of PRC-004-3 includes: Protection Systems for Facilities that are part of the BES, and Requirement R1 stipulates: '…a BES interrupting device operation in its Facility caused by a Protection System operation…' The drafting team believes these are consistent with the interpretation. The drafting team also believes there is appropriate consistency between PRC-004-3 and PRC-005-2. The Protection Systems that are described in the 4.2 Facilities section of PRC-005-2 but are not covered in the PRC-004-3 Facilities description are excluded because either there is a plan to include them in the next phase of this project, they are already addressed by another standard, or they are automation and control functions that are not protection specific.

(2) The drafting team believes Requirement R3 is essential because it provides a path to resolution if a Misoperation is identified but no cause is determined within the first 120 days.

(3) Requirement R2 states: Within 60 calendar days of identifying the cause of each Misoperation…

Organization	Yes or No	Question 9 Comment
(4) The drafting team agrees and revised Requirement R4 to eliminate the Parts. **(5) The drafting team modified Measure M4 to read: '…The evidence may also include dated work management program records, dated work orders, or dated maintenance records.'**		
Orange and Rockland Utilities		As a result of the new BES Definition (100 kV Bright-line), some new BES assets could be identified. The timeline proposed in R1, R2, and R3 in this Standard should not apply to the newly identified BES assets.
Response: Thank you for your comment. **The Implementation plan for the definition of BES states: Compliance obligations for Elements included by the definition shall begin 24 months after the applicable effective date of the definition. The drafting team believes that the 24 months allowed with the BES definition provides ample time to implement all of the requirements of PRC-004-3.**		
ITC		1) Based on the specified time intervals quarterly reports will likely hinder the process, suggest changing the data submittal to semiannual and for it to be submitted within 90 days following the end of the first or second half of the year. This comment was provided in July 2011, but the response did not explain the reason for quarterly reports. If the SDT feels it should remain, than please provide a technical justification for this decision. 2) Has the "Application Guidelines" been thoroughly reviewed? Why haven't there been any questions regarding what is in these guidelines? None of the Requirements, Measures or Compliance sections mentions it, so it should be treated only as a reference-guide. 3) R2, first bullet point requires an entity to analyze the applicability of a CAP to other protection systems. This should be removed as it exceeds the scope of this standard.
Response: Thank you for your comment. **1) The drafting team has removed all reporting obligations from the draft standard.**		

Organization	Yes or No	Question 9 Comment
2) Application Guidelines are included as part of the NERC "Results Based Standard" format. They contain no requirements or measures, and are intended to be a reference. 3) An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another misoperation and having an adverse effect on reliability. 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.		
Souhwest Power Pool Reliability Standards Development Team		1) Can Attachment 1 be tabbed format or something easier to use than the long spreadsheet provided? 2) Also we don't agree that the quarterly interval and if this is in conjunction with TADS and GADS then both of these are only reported annually. 3) In R2 under the first bullet the way it reads it would seem that you have to look at your entire system for a single misoperation. In example if you had the wrong setting on a single 421 do you have to go and look at every 421 on your system. This seems overly burdensome and could lead to someone constantly looking at the system. If you had a certain relay failure at one location do you go to all other locations that have that relay? If so then would you have to prove that at other locations you don't have this particular relay? The team may want to look at rewording this bullet maybe taking a sample of equipment or adding an additional bullet and gather all the CAPS for the year and review the system over a 24 month period, but doing this all the time seems overly burdensome. 4) Under the Application Guidelines generator protection section it has some language that is conflicting with section 6 of the proposed definition. We would suggest that the reference in the guidelines be removed. This could cause confusion with the industry and lead to miss classification of misoperations. Protection System operations which occur with the protected Element out of service, that trip any in-service Elements are Misoperations. 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 is unrelated to on-site maintenance, testing,

Organization	Yes or No	Question 9 Comment
		construction or commissioning activities.
Response: Thank you for your comment. 1) The Quarterly Protection System Misoperation Reporting Template is reviewed annually by the ERO-RAPA group and the NERC System Protection and Control Subcommittee. Attachment 1 provides field descriptions and sample data for completing the reporting template. 2) The drafting team has removed all reporting obligations from the draft standard. 3) An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another misoperation and having an adverse effect on reliability. 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. 4) The drafting team revised the Application Guideline to read: 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.		
CenterPoint Energy		CenterPoint Energy recommends deleting R4.2 which states the following: "Maintain detailed implementation records of each CAP or action plan including dated information surrounding any revision(s) and completion." With R4.1 being a performance-based requirement to "Implement the CAP or action plan", CenterPoint Energy believes it is unnecessary to establish a requirement related to documentation needs.
Response: Thank you for your comment. The drafting team agrees and revised Requirement R4 to eliminate the Parts.		
MISO		Clarification should be provided of what approvals or coordination the identified responsible entities need to undertake if a Corrective Action Plan (CAP) includes some operational solutions provided by a system operator.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comment. **The interaction between the Protection System owner and their system operator must be worked out between the two. It should be indicated in the CAP how operating instructions were modified to prevent a Misoperation from recurring.**		
Essential Power, LLC		Compliance section C1.4 contains a requirement to report to the RE – this needs to be in the requirement section of the standard.
Response: Thank you for your comment. **The drafting team has removed all reporting obligations from the draft standard.**		
Modesto Irrigation District		Concept of standard is generally very good. Please remember to keep overall reliability goals in mind, and not have entities (especially small ones like ours) get bogged down in paper-trail activities.
Response: Thank you for your comment. **Results Based Standards are intended to focus on what is beneficial to the reliability of the BES.**		
Manitoba Hydro		1) Effective Date - The language regarding the effective date needs to contemplate that Manitoba Hydro, like some other Canadian jurisdictions, will not have effective dates that are tied to Board of Trustees approval. We assuming that is what the proposed reference to 'laws applicable to such ERO governmental authorities' means but this is somewhat confusing. It would be more accurate to refer to the laws applicable to such functional entities. 2) Background - We are not clear on whether the 'Background' section of the proposed standard becomes part of the standard when final or if it's just included at this stage when the proposed language is being circulated. Assuming it does become part of the standard, there are several issues with this section as drafted. There needs to be some sort of introductory sentence at the beginning of the paragraph that explains that PRC-004-3 is designed to replace PRC-004-2a and PRC-003-0

Organization	Yes or No	Question 9 Comment
		because otherwise there is no context for why these two standards are being discussed. The full name of the standard should be used in the fourth line (missing the words “Identification and Correction”). The NOPR is discussed without any explanation of what it is - the full name, date published, by FERC etc is needed. The same can be said for the reference to the SAR further down the page. 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". 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. 3) R2 - More details should be provided regarding what level of detail is required when developing a CAP. Perhaps a template could be developed and attached to this standard. 4) Also, the wording of R2 should be made more consistent with the wording of R3. R2 implies that a cause will always be identified. We suggest the words “For each Misoperation with an identified cause(s)” be added at the beginning of R2. 5) R3 - The second bullet regarding the declaration should be re-worded to be consistent with the wording in R2. 6) C. Compliance - (i) An acronym is assigned to CEA in 1.1, but it is used in full in 1.2. This is not necessary. (ii) The term “BES Protection Systems” is used in C. Section 1.2. It would be more accurate to use the term given in 4. Applicability, Section 4.2.1 “Protection Systems for Facilities that are part of the BES”. (iii) C. Section 1.4 refers to PRC-004. It should refer to PRC-004-3. 7) Technical Guidelines - Proper and complete references to document they refer to should be provided. For example, the July 2011 Risk Assessment doesn't indicate who published this or conducted this, where it is available, etc.
Response: Thank you for your comment.		

Organization	Yes or No	Question 9 Comment
1) The language used for the Effective Date description is boiler plate language used in all NERC Reliability standards. 2) The Background section is included in the final version of the approved standard. The drafting team included the full name of the standard. The drafting team removed the reference to the NOPR and replaced it with FERC Order No. 693. 3) The drafting team believes the Protection System owner should be allowed the freedom to draft each CAP based on the aspects of each Misoperation. 4) The Requirement R2 wording directs the Protection System owner to develop a CAP if a Misoperation cause is identified. The drafting team declines to make the suggested change. 5) The declaration from Requirement R2 applies when a cause has been identified but there are specific reasons why corrective actions cannot or should not be performed. The declaration from the second bullet of Requirement R3 applies when a cause has been not identified and there are specific reasons why the investigation is going to be terminated. Consistent wording would blur the distinction between them. 6) The drafting team made the suggested changes other than the BES Protection System recommendation. 7) The drafting team has added a link to the referenced document in a footnote.		
Entergy Services, Inc. (Transmission)		Entergy is concerned with the lack of definition surrounding the statement "review each Protection System operation" in R1.
Response: Thank you for your comment. The level of scrutiny required to designate if an operation of a Protection System was proper or not is left to the Protection System owner to determine. Each entity must review each of its Protection System operations and determine whether the operation should be categorized as a Misoperation based on its available information.		
El Paso Electric		EPE believes additional clarity under the “Additional Compliance” section would be helpful as it relates to reporting misoperation data. EPE believes the insertion of some additional language may provide clarity, such as “.....shall submit data identified on Attachment 1 for misoperations identified within a quarter...”

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comment. **The drafting team declines to make the suggested change.**		
Portland General Electric Company		1) 4.2.2 excludes UVLS from this standard due to the existence of PRC-022, but it is expected that PRC-022 will be superseded much like its UF counterpart PRC-009. Rather than requiring a revision of PRC-004, 4.2.2 should be worded such that UVLS schemes would be covered by PRC-004-3 at such time as PRC-022 is retired. 2) Additional resources and signification database modifications will be required to ensure proper documentation of compliance.
Response: Thank you for your comment. **1) The drafting team must work within the constraints of the project's SAR.** **2) The drafting team believes the proposed level of documentation is appropriate.**		
Clark Public Utilities		I am confused on the requirement to provide a quarterly report. In the current draft the reference to this requirement appears in Section 1.4 of the Compliance Monitoring Process. This requirement does not appear to be in the Requirements and Measures section. The quarterly reporting also does not appear to be in the Violation Severity Levels. So it appears that in this draft, there is no real "Requirement" that a quarterly report be submitted and there is no assignment of a violation to those TOs, GOs, and DPs that do not submit a quarterly report. Is that so or am I missing something? This seems odd. If TOs, GOs, and DPs are supposed to submit a quarterly report, why isn't this included in the Requirements? Please eliminate this ambiguity. Either add the reporting to a Requirements provision or get rid of the reference to the reporting requirement in the Compliance Monitoring section.
Response: Thank you for your comment. **The drafting team has removed all reporting obligations from the draft standard.**		

Organization	Yes or No	Question 9 Comment
Cleco Corporation		1) In R2 under the first bullet the way it reads it would seem that you have to look at your entire system for a single misoperation. In example if you had the wrong setting on a single 421 do you have to go and look at every 421 on your system. This seems overly burdensome and could lead to someone constantly looking at the system. If you had a certain relay failure at one location do you go to all other locations that have that relay? If so then would you have to prove that at other locations you don't have this particular relay? The team may want to look at rewording this bullet maybe taking a sample of equipment or adding an additional bullet and gather all the CAPS for the year and review the system over a 24 month period, but doing this all the time seems overly burdensome. 2) Under the Application Guidelines generator protection section it has some language that is conflicting with section 6 of the proposed definition. We would suggest that the reference in the guidelines be removed. This could cause confusion with the industry and lead to miss classification of misoperations.
Response: Thank you for your comment. **1) An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another misoperation and having an adverse effect on reliability. 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.** **2) The drafting team revised the Application Guideline to read: 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.**		
Wisconsin Electric		In the Applicability section, in 4.2.3 relay functions not included, under 4.2.3.1 Control: add "Generator Excitation controls/limiters and turbine controls" to the existing exclusions list. The revised wording suggested is: "4.2.3.1 Control (e.g. controlled shutdown of generators, generator excitation controls/limiters, turbine controls, capacitor or reactor bank switching".

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comment. **The drafting team revised the Applicability Section 4.2.4 to read: Non-protective functions that may be imbedded within a Protection System are not included (see Guidelines and Technical Basis section for detailed examples).**		
City of Austin dba Austin Energy		In the Applicability text box, the following phrase “of the automation portion” should likely be “or the automation portion.”
Response: Thank you for your comment. **The drafting team corrected the typographical error.**		
Indiana Municipal Power Agency		1) In the Application Guidelines, page 18 of 22, the following statement is made: "The initial evidence, which may also be documented separately, contains the sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records." By making this statement in the Application Guidelines, it seems to be requiring entities to have sequence of events AND Disturbance Monitoring Equipment records. IMPA believes that this is not the intent of the SDT and recommends using the words "may contain the sequence of events, relay targets,... 2) "In addition, IMPA agrees with the comments that Florida Municipal Power Agency submitted for this question.
Response: Thank you for your comment. **1) The standard does not require any additional monitoring equipment to be installed. Each TO or GO must review each of its Protection System operations and determine whether the operation should be categorized as a Misoperation based on its available information. The entity will use whatever means at their disposal in order to determine whether the operation was correct or not which may include available DISTURBANCE MONITORING EQUIPMENT. The drafting team modified the sentence in the Application Guidelines to address your concern. The Application Guidelines are reference information only and are not mandatory and enforceable.** **2) Please see the drafting team’s response to Florida Municipal Power Agency.**		

Organization	Yes or No	Question 9 Comment
US Bureau of Reclamation		Including the TADS information provided under the NERC Rules of Procedure is in conflict with this standard. TADS' reporting is on an annual basis. By including the TADS event ID, the standard would require quarterly reporting of the TADs event. The inclusion introduces the conflict between the rules of procedure and a standard. Including the quarterly reporting as part of the compliance information is not consistent with standard requirements. There is requirement VRF or VSL assigned to the reporting and therefore no compliance violation can be assessed for failure to respond. The reporting information is not subject to a requirement per Commission guidance since it is only for metrics and administrative purposes per the SDT. The information collected under this standard is inconsistent with the information collected for Transmission system events. TADs event data is collected under the NERC Rules of Procedures. The standard should be modified to remove the reference to the additional compliance information and have the information collected under the NERC Rules of Procedures.
Response: Thank you for your comment. **The drafting team has removed all reporting obligations from the draft standard.**		
Nebraska Public Power District		1) It sounds like a CAP is a case by case document for each misoperation and does not need to be a formal CAP process document that explains the steps that will be followed for all misoperation investigations. Is this correct? 2) I have concerns with the open ended nature of the statement in R2 "Develop and document 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". Specifically my concerns are with the last part referring to "at other locations". I am curious how the STD would consider if a miscoordination resulting in a misoperation were to happen on their system. Would they consider reviewing the coordination for every relay at every substation on their system? This requirement has value yet also opens the door to unreasonable CAPs as

Organization	Yes or No	Question 9 Comment
		well. This requirement also seems quite subjective in how it could be audited as well. Does the STD share this concern? 3) Will the registration criteria or BES definition be referenced to set generation sizes for reporting misoperations? The application guidelines are very helpful in explaining the SDT expectations and should continue to be part of the standard for guidance.
Response: Thank you for your comment. **1) The drafting team concurs. As defined in the NERC Glossary of Terms, a Corrective Action Plan (CAP) is defined as: A list of actions and an associated timetable for implementation to remedy a specific problem.** **2) An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another misoperation and having an adverse effect on reliability. 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.** **3) The Applicability Section, 4.2 Facilities 4.2.1 states: Protection Systems for BES Elements. The Application Guidelines are a permanent part of the standard.**		
Luminant		Luminant does not agree with Requirement R3 of the standard since there is an apparent conflict or double jeopardy with the draft standard on generator relay loadability (PRC-025-1). Luminant recommends that R3 of PRC-025-2 be removed and any event from a generator load responsive relay for review be in the draft PRC-004 standard that operates an interrupting device. The chairmen of both SDT's should consult with one another to remove any conflicts.
Response: Thank you for your comment. **This issue has been addressed by the PRC-025-1 drafting team.**		
Northeast Power Coordinating Council		1) Measurement M1 has that "Acceptable evidence for Part 1.3 may include, but is not limited to, a copy of dated investigation report or documented findings for each Misoperation." This provides a choice in a document type with either

Organization	Yes or No	Question 9 Comment
		a formal report or other method of documenting the findings. On page 22 of 28 of PRC-004-3, in the Application Guidelines section, it states "An investigation report may include...” which dictates the use of an investigation report, and eliminates the choice between a formal report or other method of documenting findings as stated in M1. The Application Guidelines should be consistent with the standard portion of the document. 2) There is a typographical error on the first bulleted item on page 6 of the standard. This item should read: Analyze Misoperations of Protection Systems for Facilities that are part of the BES to determine the cause(s).
Response: Thank you for your comments. **1) The drafting team revised the Application Guideline to address your concern.** **2) The drafting team corrected the text.**		
NextEra Energy Inc.		1) NextEra encourages the Standards Drafting Team to improve the wording used in R2. At this time, the wording appears to apply to all situations without qualification and does not consider several situations that may be relevant. To clarify the language, NextEra recommends the following changes to R2. ”R2. Within 60 calendar days of identifying the cause(s) of each Misoperation pursuant to R1.3, the Transmission Owner, Generator Owner, or Distribution Provider shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning] o Draft a Corrective Action Plan (CAP) for the identified Protection System component(s), including, if applicable, the following: (i) An evaluation of the CAP’s applicability to the entity’s other Protection Systems (ii) An explanation of why corrective actions are either: (i) Beyond the entity’s control; (ii) Cost prohibitive/significantly impacted by cost considerations;

Organization	Yes or No	Question 9 Comment
		(iii) Not to be implemented for over 5 years (iv) Would reduce BES reliability." 2) Similar to the re-write of R2, NextEra does not see the need for a "declaration" in R3. Thus, NextEra recommends that the second bullet in R3 be redrafted to read:" o An explanation of why no further actions will be taken." 3) NextEra opposes the use of "detailed" in R4.2 as unnecessary, subjective and onerous. PRC-004-3 should not be written so that an entity can be found in violation because of subjective judgments on what is or what is not detailed. 4) Further, NextEra finds that the clarity of R4.2 may be improved. Thus, NextEra recommends that R4.2 be redrafted as follows:" 4.2 Maintain implementation records for each CAP and action plan, including the dates of any revision(s) and completion." 5) Lastly, for clarity, NextEra also believes there should be linkage between R2 and R4 on the issue of applicability to other Protection Systems at other locations, and, thus, suggests the following changes to R4.1. "4.1 Implement the CAP or action plan, including, as applicable, the entity's Protection Systems at other locations that were identified in R2."

Response: Thank you for your comments.

1) The drafting team declines to make the suggested changes.

2) The drafting team declines to make the suggested changes.

3) The drafting team revised Requirement R4 to eliminate the Parts.

4) The drafting team revised Requirement R4 to eliminate the Parts.

Organization	Yes or No	Question 9 Comment
5) An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another misoperation and having an adverse effect on reliability. 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.		
Detroit Edison		Overall, the draft standard is good and we already comply with most of the requirements as a general practice. The concern is around ability to properly analyze and determine iof operations, specifically around generation, would be considered slow. As of today, there is not adequate monitoring (and many of the conditions are far too dynamic to properly determine what the proper operating time should have been) to determine how quickly a relay responded to a "other than fault" condition. Would recommend a "yes" vote if there was wording stating that it is not a misoperation if the data that exists is not of a fine enough resolution to prove a relay was slow.
Response: Thank you for your comments. **The standard does not require any additional monitoring equipment to be installed. Each TO or GO must review each of its Protection System operations and determine whether the operation should be categorized as a Misoperation based on its available information. The entity will use whatever means at their disposal in order to determine whether the operation was correct or not which may include available DISTURBANCE MONITORING EQUIPMENT.**		
Associated Electric Cooperative Inc - JRO00088		Page 6, Line 1,Replace: "Analyze Misoperations Protection Systems"With: "Analyze Misoperations of Protection Systems" Rationale: Grammar and alignment with phrase from preceding bullet
Response: Thank you for your comments. **The drafting team corrected the text.**		
Dairyland Power Cooperative		1) R2 and R3 the second bullet is administrative and redundant, and does not aid in the protection of the BES. Recommend removing the second bullet from R2 and R3. This is captured within the first bulleted item.

Organization	Yes or No	Question 9 Comment
		2) R4.2 is administrative and does not aid on the protection the BES. Recommend removing R4.2

Response: Thank you for your comments.

1) **The drafting team declines to make the suggested changes. A declaration provides a means of closing unresolved Misoperations where corrective actions are beyond the entity's control or would reduce BES reliability, or where no further actions can be taken.**

2) **The drafting team agrees and revised Requirement R4 to eliminate the Parts.**

Organization	Yes or No	Question 9 Comment
The United Illuminating Company		1) R2 should not specify that the CAP contains an activity to evaluate applicability to all of the entity's Protection System. It could create a situation where check-sheets are required with sign-offs for review of all systems. 2) R4.2 is of concern with the requirement to maintain detail implementation records of each CAP or action plan. Detail is an ambiguous word that cannot be complied to. The compliance burden to provide detailed implementation records is excessive. A Transmission Owner is audited every 6 years. A TO will need to provide detailed records of CAP's and action plans for 6 years. The only organization receiving a benefit from this requirement is the NERC Audit team. All that should be required by the Standard is the date of completion on the CAP implementation. 3) Additionally, There should be no requirement to record revisions to the CAP.

Response: Thank you for your comments.

1) **An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another misoperation and having an adverse effect on reliability. 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.**

2) **The drafting team revised Requirement R4 to eliminate the Parts.**

3) **The drafting team revised Requirement R4 to eliminate the Parts.**

Organization	Yes or No	Question 9 Comment
Public Service Company of New Mexico		R3 as drafted could be difficult to audit. PNMR suggests additional clarity be provided around what would be an acceptable criteria to invoke "A declaration explaining why no further actions will be taken." As the standard is written now it appears that an RE could just declare a misop as having an unquantifiable cause and then declare that no further action is warranted or will be taken.
Response: Thank you for your comments. **Measure M3 states the entity must have evidence that includes a dated action plan or a dated declaration. A "no action plan" declaration would typically include any investigative actions taken to determine the cause (along with the date performed), and justification for taking no additional investigative actions.**		
ReliabilityFirst		ReliabilityFirst Abstains and offers the following additional comments for consideration: 1) ReliabilityFirst believes there are extra and unneeded deadlines in the standard that do not provide a reliability benefit. 2) ReliabilityFirst believes there is a potential for late identification of Misoperations which will result in violations even if they are not particularly significant to grid reliability. For example, capacitor bank trips occur every day as part of normal switching. It may not be obvious if it was by a Protection System Misoperation, particularly if a relay is used for multiple purposes like ON/OFF switching control and protection. 3) ReliabilityFirst has a concern that there is no maximum time to complete CAPs listed in the draft standard. Of particular concern is failure to trip (- during Fault) type Misoperations. The cause should be either mitigated or the CAP completed in something like 6 - 12 month time period.
Response: Thank you for your comments. **1) The reliability of the system relies on prompt discovery, investigation and mitigation of any Misoperation to avoid**		

Organization	Yes or No	Question 9 Comment
reoccurrence or occurrence in other Protection Systems. 2) The drafting team believes 120 days is an adequate amount of time to review Protection System operations and identify any Misoperations. 3) Establishing fixed time limits for the conclusion of CAP is impractical because of the wide spectrum of Misoperation causes and the variety of corrective actions. A schedule or timetable is required to be included in the CAP.		
Bonneville Power Administration		Section 4.2 is titled Facilities. The NERC definition of facility is a set of electrical equipment that operates as a single BES element. The NERC definition of element is 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. Based on these definitions, it would seem that a protection system is not an element or a facility. 1) BPA suggests renaming Section 4.2 to “Equipment” or “Systems”. 2) Section 4.2.2 should be renamed from “Facilities not included” to “Protection Systems not included” or something similar. 3) The last paragraph of Section A.5, Background notes that PRC-004-WECC-1 overlaps with this standard and says that entities are expected to comply with the more stringent standard. Rather than leave it up to the entity to determine which of the standards is more stringent, BPA suggests simply stating which of the standards takes precedence and which can be ignored.
Response: Thank you for your comments. 1) Section 4.2 Facilities is a part of the NERC results based standard template. It is beyond the scope of the drafting team to modify the template. 2) The drafting team revised Section 4.2.3 (the former 4.2.2) to eliminate the term ‘Facilities’ by incorporating the subsections into the 4.2.3. 3) Regional standards are required to be more stringent than the continent-wide NERC Reliability Standards. Entities are required to comply with both the continent-wide NERC Reliability Standards and any Regional standards issued by their		

Organization	Yes or No	Question 9 Comment
Region.		
Sacramento Municipal Utility District		SMUD agrees with the concepts for addressing misoperations presented in this draft PRC-004 standard. We do have concerns with the ‘zero-defect’ approach and urge the Standard Drafting Team to embrace the integration of Internal Controls into this reliability standard to help the entity achieve the standard’s reliability objectives. This would better align the standard with ongoing activities such as the FFTR, Paragraph 81 and other tasks underway. We thank you for considering all of our comments in Questions 1 - 9 on this standard.
Response: Thank you for your supportive comments. **The drafting team believes the current approach meets the reliability objectives established in the SAR for this project.**		
American Electric Power		1) The following excerpts from the "Consideration of Comments" document should be added to item "(3)" of the "Guidelines and Technical Basis" section to clarify the intent of the "Slow Trip" category: “In many cases high speed protection is installed as part of the utilities standard practice without having the need for high speed protection for meeting TPL requirements. A slow trip of this protection system would not negatively impact the BES, so it does not need to be reported. However, even if high speed clearing is not required, the Protection Systems must coordinate between zones to prevent a Misoperation (e.g. an over trip). 2) ”Facilities 4.2 - Should the text “Also see Guidelines and Technical Basis section for detailed examples” be taken out of 4.2.3.1 and applied more broadly to the standard? 3) In the first bullet of R2, may an evaluation of the CAP's applicability to the entity's Protection System at other locations result in no additional actions being taken? 4) Is the "evaluation of the CAP's applicability to the entity's Protection System at other locations" part of the quarterly reporting?

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comments. **1) The drafting team revised the Application Guideline as suggested.** **2) The drafting team revised the Facilities Section 4.2 and eliminated 4.2.3.1. The Application Guidelines do expound on the non-protective functions of relays excluded from the standard.** **3) Yes. It is left to the entity to determine the range and impact of the problem. An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another Misoperation and having an adverse effect on reliability. 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.** **4) The drafting team has removed all reporting obligations from the draft standard.**		
Consumers Energy		The quarterly reporting of Misoperations provides no benefit to the reliability of the Bulk Electric System and the entities are required to spend additional resources to develop these quarterly reports instead of focusing on the actual reliable operation of the BES. Performance metrics can be determined on a yearly basis, through annual reporting.
Response: Thank you for your comments. **The drafting team has removed all reporting obligations from the draft standard.**		
ISO/RTO Standards Review Committee		The SRC seeks clarification of what approvals or coordination the identified responsible entities need to undertake if a Corrective Action Plan (CAP) includes some operational solutions provided by a system operator.
Response: Thank you for your comment. **The interaction between the Protection System owner and their system operator must be worked out between the two. It should be indicated in the CAP how operating instructions were modified to prevent a Misoperation from recurring.**		
Tacoma Power		1) Under Applicability (comment box to side), change 'RMS' to 'RAS.'

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 9 Comment</th></tr>
<tr><td></td><td></td><td>2) Why does "(e.g., data collection)" need to be included under 4.2.3.2? Data collection does not operate anything.
3) Referring to the second bullet of page 5 (red-line version), change "...Misoperations Protection..." to "...Misoperations of Protection..."</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1) The drafting team made the correction.
2) The drafting team revised the Facilities Section of the standard and eliminated 4.2.3.2.
3) The drafting team made the correction.</td></tr>
<tr><td>Western Area Power Administration</td><td></td><td>We agree that these are good business practices and, in fact, we are currently performing these practices already.
1) However, we have a great deal of concern that the documentation burden required to meet compliance continues to increase exponentially. We would like to point out that the current documentation requirements are diverting a significant portion of our resources away from system improvements.
2) Please add the following items (found in the Applications Guidelines) directly into the standard requirements:
a) Delayed fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high speed performance is not required by planning studies associated with the TPL standards or by coordination requirements with other Protection Systems.
b) An unintended operation as a result of on-site maintenance, testing, construction or commissioning is not a Misoperation.
c) In some cases, where zones of protection overlap, the owner of BES Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.
d) Failure to automatically reclose after a Fault is not included as a Misoperation because reclosing equipment is not included under the definition of Protection</td></tr>
</table>

Organization	Yes or No	Question 9 Comment
		Systems.
Response: Thank you for your comments. **1) The requirements and associated documentation ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion. Consequently, the drafting team does not believe this documentation detracts from the reliable operation of the BES.** **2a & b) These statements are included in the definition of Misoperation.** **2c &d) The drafting team believes these statements belong in the Application Guidelines rather than the requirements and declines to make the suggested changes.**		
JEA		We believe this would be a good candidate for the new cost benefit approach. Also we believe that this is the wrong approach. NERC should focus on fixing the problem (PRC003 not being approved) by working on PRC003 instead of changing PRC004 to address deficiencies caused by lack of an approved PRC003 standard.
Response: Thank you for your comments. **The drafting team disagrees and believes this approach is the best way to address the investigations of Misoperations uniformly. Furthermore, the drafting team is bound by the scope of the SAR associated with this project and does not have the latitude to follow your suggestion.**		
PSEG		We have provided new language below that continues after our R4 above. R5 addresses implementation of the CAP or action plan. R6 requires reporting of data in Attachment 1. We believe that providing the data in Attachment 1 should be a requirement instead of being addressed in the "Additional Compliance Information" section. 1) R5. For each CAP or action plan, the Transmission Owner, Generator Owner, and Distribution Provider shall implement the CAP or action plan. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Long-Term Planning] M5. Each Transmission Owner, Generator Owner, and

Organization	Yes or No	Question 9 Comment
		Distribution Provider shall have evidence for Requirement R5 that includes dated records which document the implementation of each CAP and action plan, such as work orders or maintenance records that document the completion of work or maintenance, including documentation of revisions for each CAP or action plan. 2) R6. Each Transmission Owner, Generator Owner, or Distribution Provider shall submit PRC-004 - Attachment 1 to its Regional Entity within two calendar months following the end of each calendar quarter. [Violation Risk Factor: Low] [Time Horizon: Operations Planning, Long-Term Planning] M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R6 that it transmitted PRC-004-3 - Attachment 1 to its Regional Entities within two calendar months following the end of each calendar quarter. 3) We have also addressed the "Facilities" portion of the standard in the "Applicability" section and suggest the language below, parts of which were taken from PRC-005-2. The Protection Systems in 4.2.1 and 4.2.2 provide protective functions. Section 4.2.3.3 excludes UFLS systems whose operation is evaluated in PRC-009-0. While it is clear that the team wanted to exclude relays such as reveres power relays for generators, their description of these as providing "non-protective functions" is inaccurate since they prevent a generator from motoring during shutdown. They protect the generator. We have excluded those applications in our Section 4.2.3.4 because the operation of an interrupting device caused by a reverse power relay is associated with a normal generator shutdown. The Misoperation of such a relay results in the motoring of a generator, and while that can create a serious problem for a Generator Owner who is incented to evaluate such Misoperations absent a standard, it does not create a BES reliability issue. 4.2. Facilities 4.2.1 Protection Systems that are installed for the purpose of

Organization	Yes or No	Question 9 Comment
		detecting Faults on BES Elements (lines, buses, transformers, etc.) or abnormal conditions. 4.2.2 Protection Systems for generator Facilities that are part of the BES for the purpose of detecting faults or abnormal conditions, including: 4.2.2.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays. 4.2.2.2 Protection Systems for generator step-up transformers for generators that are part of the BES. 4.2.2.3 Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES). 4.2.2.4 Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays. 4.2.3 Facilities not included 4.2.3.1 Special Protection Systems (SPS) or Remedial Action Schemes (RAS) 4.2.3.2 Undervoltage load shedding (UVLS) systems 4.2.3.3 Underfrequency load shedding (UFLS) systems 4.2.3.4 Relays that operate for the normal shutdown of an Element. 4) Finally, we believe in the Application Guideline, the third sentence in the first paragrgaph on p. 18 of 22 is written too restrictley. We suggest this language instead: The initial evidence, which may also be documented separately, MAY CONTAIN [delete “contains.”] the sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records, TO THE EXTENT AVAILABLE.

Response: Thank you for your comments.

Organization	Yes or No	Question 9 Comment
1) The drafting team revised Requirement R4 and it is similar to your suggested Requirement R5. 2) The drafting team has removed all reporting obligations from the draft standard. 3) The drafting team revised the Facilities Section 4.2 but declined your suggestions. 4) The drafting team revised the text to read '…contains the sequence of events, relay targets and a summary and Disturbance Monitoring Equipment (DME) records as appropriate.'		
Colorado Springs Utilities		We understand that this was an arduous standard to develop, and it required extensive explanations for requirements and measurements. We agree with the concepts presented in PRC-004-3, and we believe it was very well-written. We appreciate the effort that went into developing and reviewing this revision. However, frequent revisions of standards, coupled with frequent revisions of definitions, do not help to maintain consistent procedures for ensuring the reliability of our protection systems. We suggest that national standards only require what is deemed absolutely necessary on a national level. Any further requirements and recommendations should be provided by Regional Entities. This will mitigate misinterpretations of the standard and lessen the amount of revisions to the standard.
Response: Thank you for your comments.		
Seattle City Light		While Seattle City Light generally agrees with the concepts presented in the draft Standard and appreiates the effort required to develop and review Standards, SCL finds the reliability improvements promised by the draft to be diluted with unnecessary backwards-looking compliance activities. 1) The draft appears tone-deaf to the changes at NERC regarding purely administrative tasks (e.g., Paragraph 81 effort to remove them, whereas this draft adds several such as R4.2 and the second bullets of R2 and R3). One example is the emphasis on meeting and documenting multiple dates for each

Organization	Yes or No	Question 9 Comment
		Misoperation. Another is a need to document completion of each Misoperation CAP almost as if it were a Mitigation Plan to correct a Self-Reported violation, rather than, for example, relying primarily on the corrective action documentation already reported for GADS and TADS. 2) The draft also would benefit from application of the non-zero-defect concepts introduced with the latest draft of CIP version 5. Changes such as these will minimize the need to revise the Standard yet again to align with present directions.
Response: Thank you for your comments. **1) The requirements and associated documentation ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion. Consequently, the drafting team does not believe this documentation detracts from the reliable operation of the BES.** **2) The drafting team believes the current approach meets the reliability objectives established in the SAR for this project.**		
New York Power Authority		None.
Response: Thank you.		

END OF REPORT