Consideration of Comments

Protection System Maintenance and Testing - Project 2007-17

The Protection System Maintenance and Testing Drafting team thanks all commenters who submitted comments on the 3rd draft of the standard for Protection System Maintenance. These standards were posted for a 30-day public comment period from June 18, 2012 through June 27, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 51 sets of comments, including comments from approximately 170 different people from approximately 110 companies representing all 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Protection_System_Maintenance_Project_2007-17.html

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 of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration of all Comments Received:

Definitions:

No changes were made to the Definitions.

Applicability:

No changes were made to the Applicability.

Requirements:

No changes were made to the Requirements.

Tables

In Table 1-2, the interval for the second portion of the first row of the table was changed from 12 years to 6 years. Also, in Table 1-2, "channels" was modified to "communications systems" in two locations,

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

and the Component Attributes in the last row were modified to clarify that all attributes must be present to use the associated intervals and activities.

Editorial changes were made to Tables 1-4c, 1-4d., and 1-4e. The words "Protection System" were added to the headers of Tables 1-4c and 1-4d; in Table 1-4e, a redundant "only" was removed.

No additional changes were made to the Tables.

Measures

No changes were made to the Measures.

VRFs and VSLs

No changes were made to the VRFs and VSLs.

Version History

The Version History was updated to reflect the latest approved version of PRC-005.

Implementation Plan

The Implementation Plan was revised to retire the four legacy standards upon full implementation of PRC-005-2 rather than upon the Effective Date. Clarifying language was added to address this change.

Supplementary Reference and FAQ Document

Numerous changes, both technical and editorial, were made throughout the Supplementary Reference and FAQ.

Mapping Document

Minor clarifying changes were made to the Mapping Document.

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.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Michael Jones	National Grid	NPCC	1
9.	David Kiguel	Hydro One Networks Inc.	NPCC	1
10.	Michael R. Lombardi	Northeast Utilities	NPCC	1

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

11. Randy MacDonald	New Brunswick Power Transmission	NPCC	9
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. Brian Robinson	Utility Services	NPCC	8
19. Michael Schiavone	National Grid	NPCC	1
20. Wayne Sipperly	New York Power Authority	NPCC	5
21. Tina Teng	Independent Electricity System Operator	NPCC	2
22. Doanld Weaver	New Brunswick System Operator	NPCC	2
23. Ben Wu	Orange and Rockland Utilities	NPCC	1
24. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

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

Additional Member	Additional Organization	Region	Segment Selection
1. Fred	Bryant	WECC	1
2. Jason	Burt	WECC	1
3. Brenda	Vasbinder	WECC	1
4. Heather	Laslo	WECC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Nick Wehner	ACES Power Marketing Standards Collaborators	X		X	X	X					

Additional Member	Additional Organization	Region	Segment Selection
1. Ashley Gonyer	East Kentucky Power Cooperative	SERC	1, 3, 5
2. John Shaver	Arizona Electric Power Cooperative	WECC	1, 4, 5
3. John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
4. Mark Ringhausen	Old Dominion Electric Cooperative	SERC	3, 4
5. Mohan Sachdeva	Buckeye Power, Inc.	RFC	3, 4
6. Scott Brame	North Carolina Electric Membership Corporation	RFC	1, 3, 4, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1. Epifanio Martinez		IID	WECC 1, 3, 4, 5, 6										
2. Nando Gutierrez		IID	WECC 1, 3, 4, 5, 6										
3. Tony Allegranza		IID	WECC 1, 3, 4, 5, 6										
4. Jose Landeros		IID	WECC 1, 3, 4, 5, 6										
5.	Group	Greg Rowland	Duke Energy	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Doug Hils	Duke Energy	RFC	1
2. Ed Ernst	Duke Energy	SERC	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
6.	Group	Will Smith	MRO NSRF	X	X	X	X	X	X	X			

Additional Member	Additional Organization	Region	Segment Selection
1. MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2. CHUCK LAWRENCE	ATC	MRO	1
3. TOM WEBB	WPS	MRO	3, 4, 5, 6
4. JODI JENSON	WAPA	MRO	1, 6
5. KEN GOLDSMITH	ALTW	MRO	4
6. ALICE IRELAND	XCEL	MRO	1, 3, 5, 6
7. DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8. ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9. JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10. SCOTT NICKELS	RPU	MRO	4
11. TERRY HARBOUR	MEC	MRO	3, 5, 6, 1
12. MARIE KNOX	MISO	MRO	2
13. LEE KITTELSON	OTP	MRO	1, 3, 4, 5
14. SCOTT BOS	MPW	MRO	1, 3, 5, 6
15. TONY EDDLEMAN	NPPD	MRO	1, 3, 4
16. MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17. DAN INMAN	MPC	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Jonathan Hayes	Southwest Power Pool NERC Reliability Standards Development Team	X	X	X	X	X	X				

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	Robert Rhodes	Southwest Power Pool	SPP	NA
3.	Paul Abel	Oklahoma gas and electric	SPP	1, 3, 5
4.	John Allen	City Utilities of springfield	SPP	1, 4
5.	Bud Averill	Grand River Dam Authority	SPP	1, 3, 5
6.	Clem Cassmeyer	Western Farmers Electric Cooperative	SPP	1, 3, 5
7.	Paul Cox	GDS Associates	SPP	NA
8.	Willy Haffecke	City Utilities of springfield	SPP	1, 4
9.	Julie Lux	Westar Energy inc.	SPP	1, 3, 5, 6
10.	Mahmood Safi	OPPD	MRO	1, 3, 5
11.	Sean Simpson	Board of public utilities of kansas city, kansas	SPP	NA
12.	Louis Guidry	CLECO	SPP	1, 3, 5
13.	Lindsay Sheppard	Sunflower Electric Corporation	SPP	1
14.	Steve McGie	Coffeyville	SPP	NA

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1.	M. Ferncez	FE	RFC
2.	T. Sheerer	FE	RFC
3.	D. Hohlbaugh	FE	RFC
4.	B. Orians	FE	RFC
5.	J. Chmura	FE	RFC
6.	L. Lee	FE	RFC
7.	R. Loy	FE	RFC
8.	B. Duge	FE	RFC

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

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

				1	2	3	4	5	6	7	8	9	10
10.	Group	Pawel Krupa	Seattle City Light Operations										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Pawel Krupa	Seattle City Light	WECC	1
2.	Dana Wheelock	Seattle City Light	WECC	3
3.	Hao Li	SCL	WECC	4

				1	2	3	4	5	6	7	8	9	10
11.	Group	Ron Sporseen	PNGC Small Entity Comment Group	X		X					X		

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joe Jarvis	Blachly-Lane Electric Cooperative	WECC	3
2.	Dave Markham	Central Electric Cooperative	WECC	3
3.	Dave Hagen	Clearwater Power Company	WECC	3
4.	Roman Gillen	Consumer's Power Inc.	WECC	1, 3
5.	Roger Meader	Coos-Curry Electric Cooperative	WECC	3
6.	Bryan Case	Fall River Electric Cooperative	WECC	3
7.	Rick Crinklaw	Lane Electric Cooperative	WECC	3
8.	Annie Terracciano	Northern Lights Inc.	WECC	3
9.	Aleka Scott	PNGC Power	WECC	4
10.	Heber Carpenter	Raft River Electric Cooperative	WECC	3
11.	Steve Eldrige	Umatilla Electric Cooperative	WECC	1, 3
12.	Marc Farmer	West Oregon Electric Cooperative	WECC	4
13.	Margaret Ryan	PNGC Power	WECC	8

				1	2	3	4	5	6	7	8	9	10
12.	Group	Dave Davidson	Tennessee Valley Authority					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rusty Hardison	TOM Support	SERC	1
2.	Pat Caldwell	TOM Support	SERC	1
3.	David Thompson	TVA Compliance	SERC	5
4.	Jerry Finley	Rel&Eng Engeering Stdrs	SERC	1
5.	Robert Brown	TVA Generation - Nuclear	SERC	5
6.	Tom Vandervort	TVA Generation - Fossil	SERC	5
7.	Annette Dudley	TVA Generation - Hydro	SERC	5

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

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

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

				1	2	3	4	5	6	7	8	9	10
14.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	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
15.	Group	Jennifer Eckels	Colorado Springs Utilities	X		X		X	X				

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

				1	2	3	4	5	6	7	8	9	10
16.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
17.	Individual	Cole Brodine	Nebraska Public Power District	X		X		X					
18.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
19.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
20.	Individual	Brandy A. Dunn	Western Area Power Administration	X					X				
21.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
22.	Individual	Michael Falvo	Independent Electricity System Operator		X								
23.	Individual	Jennifer Wright	San Diego Gas & Electric	X		X		X					
24.	Individual	Dale Dunckel	Public Utility District No. 1 of Okanogan County	X									
25.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
26.	Individual	Kenneth A Goldsmith	Alliant Energy				X						
27.	Individual	Thad Ness	American Electric Power	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
28.	Individual	Ed Davis	Entergy Services	X		X		X	X				
29.	Individual	Anthony Jablonski	ReliabilityFirst										X
30.	Individual	Maggy Powell	Exelon Corporation and its affiliates	X		X		X	X				
31.	Individual	Eric Salsbury	Consumers Energy			X	X	X					
32.	Individual	Chris Searles	BAE Batteries USA							X	X		
33.	Individual	Kevin Luke	Georgia Transmission Corporation	X									
34.	Individual	Brad Harris	CenterPoint Energy										
35.	Individual	Steven Wallace	Seminole Electric Cooperative, Inc	X			X	X	X				
36.	Individual	Kirit Shah	Ameren	X		X		X	X				
37.	Individual	Laurie Williams	Public Service Company of New Mexico	X		X		X	X				
38.	Individual	Steve Alexanderson P.E.	Central Lincoln			X	X					X	
39.	Individual	Wayne E. Johnson	EPRI										
40.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
41.	Individual	Travis Metcalfe	Tacoma Power	X		X	X	X	X				
42.	Individual	Jonathan Meyer	Idaho Power Company	X		X							
43.	Individual	Stephen J. Berger	PPL Generation, LLC on behalf of its Supply NERC Registered Entities					X					
44.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
45.	Individual	Martin Bauer	US Bureau of Reclamation					X					
46.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
47.	Individual	d mason	HHWP	X				X					
48.	Individual	Tony Kroskey	Brazos Electric Power Cooperative	X									
49.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
50.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
51.	Individual	William Cantor	TPI										

1. **In response to stakeholder input, the SDT made several changes to the standard and associated definitions as detailed below:**
   - **Revised the "Inspect" element of the definition of Protection System Maintenance Program (PSMP), the definition of the term Unresolved Maintenance Issues, and the definition of the term Countable Event.**
   - **Revised Clause 4.2.5.4 of the Applicability section of the standard.**
   - **Revised Table 1-2 "Component Type - Communications Systems."**
   - **Revised Tables 1-4a, 1-4b, 1-4c, 1-4d, and 1-4f "Component Type - Protection System Station dc Supply…."**

   Do you agree with these changes? If not, please indicate which changes you do not agree with and provide specific suggestions in the comment area for improvements that would allow you to support the standard.

Summary Consideration:

Some commenters continued to object to various activities and/or intervals within the tables. The drafting team made several changes detailed below in response to these comments.

1. One interval was changed – the interval for the activity in Table 1-2 for unmonitored communications systems was changed from 12 years back to 6 years as it had been in all previous postings. This change promotes consistency with similar activities within Table 1-1 (Protective Relays).
2. The language in two activities in Table 1-2 was changed from "channels" to "communications systems".
3. The language in the Component Attributes in the last row of Table 1-2 was modified to read: "Any communications system with all of the following:" to clarify that all must be present to use the related intervals and activities.
4. In Table 1-4e, a redundant "only" was removed from the Component Attributes in the last row.

A few commenters continued to contrast the Applicability (4.2.1) with the Interpretation represented in PRC-005-1b. The drafting team responded, but no changes were made.

Several comments were offered on the informational posting of the draft SAR to revise PRC-005-2 to add reclosing relays. The drafting team responded, but no changes were made.

Organization	Yes or No	Question 1 Comment

Organization	Yes or No	Question 1 Comment
Bonneville Power Administration	No	1. BPA believes the term communications system and channel needs to be clarified as to whether the intent is the communications system, a channel on the telecommunication channel, the teleprotection channel, or the teleprotection function. 2. A. Minimum battery maintenance interval is to assure that the battery plant will perform as needed, and obtain a reasonable confidence that it will continue acceptable performance until the next maintenance evaluation. Typically, any utility VLA battery application, steady state float charge/long duration discharge, a Monthly or Quarterly maintenance is excessive given a proper design/maintenance program (IEEE 450, 484, 485). There is a 60 year proven history of this. BPA recognizes that there will be specific VLA battery installations that will be required beyond this minimum. BPA recommends rolling the 4 month maintenance into the 18 month maintenance schedule. B. The scientific vetted method of determining a VLA batteries current performance, and projected performance, is a capacity test. This has been scientifically verified at least 10 times since 1919, with consistent results. This approach is consistent with the IEEE 450, as well as many other standards, and is supported by the industry. If an alternate approach using measured parameters to predict current and future battery performance is to be allowed, then it must assure the same result. C. Battery monitoring does enable measurements to be made automatically with greater frequency. Additionally it provides the ability to collect, store, report, and analyze data from the battery even during an outage. It does not mitigate the necessity to perform battery maintenance. If battery monitoring is performed mandatory maintenance should also be required on the monitor.
Response: Thank you for your comments.		

Organization	Yes or No	Question 1 Comment
1. The SDT has modified "channel" to "communications system" in Table 1-2 in response to your comment. Discussion was also added to Section 15.5.1 of the Supplementary Reference and FAQ Document to explain "channel". 2. See below: A. The drafting team disagrees with your assertion that the 4 month interval should be extended to the 18 month maintenance schedule for performance of maintenance activities. The 18 month maximum maintenance interval for the unmonitored VLA battery used in a Protection System station dc supply is too long for verification that there is any voltage on the dc supply, that each cell of the unmonitored station battery is inspected to see that it has electrolyte in it, or that the unmonitored dc supply is inspected for unintentional dc grounds. B. The drafting team agrees with you that the performance capacity test is a well proven method to determine the capacity of a station battery and provides an indication of the health of the battery. However, there are other measurements that are indicative of battery health and performance that when trended to the station battery baseline and examined along with the other maintenance activities required in Table 1-4 of the standard can indicate that station battery can perform as manufactured. By trending periodically measured properties indicative of battery performance while serving its Protection System, the Transmission Owner, Generator Owner or Distribution Provider can develop a condition based method to determine (1) when a station battery requires a capacity test (instead of performing a capacity test on a predetermined, prescribed interval), (2) when an individual cell or battery unit should be replaced, or (3) if the station battery should be replaced without performing a capacity test, based on the analysis of the trended data. C. The drafting team agrees that, "battery monitoring does enable measurements to be made automatically with greater frequency. Additionally it provides the ability to collect, store, report, and analyze data from the battery even during an outage." Besides these positive qualities it alleviates the necessity to physically perform - in the station - most of the battery maintenance activities listed in Table 1-4 (see Table1-4 (f)). However, the inspection of the battery, its cells and the physical condition of the battery rack are mandatory maintenance activities that must be performed by the maintenance workforce at the station or via remote control. Concerning the maintenance of the monitoring system, please refer to Table 2 (Alarming Paths and Monitoring) of the standard for the mandatory maintenance that is required on the monitor.		
Imperial Irrigation District (IID)	No	IID does not agree with the proposed changes to the definition of Inspect using the word Examine and suggests using Visual Examination instead.
Response: Thank you for your comments. The SDT believes the word 'Examine' is correct.		

Organization	Yes or No	Question 1 Comment
Western Area Power Administration	No	The Standard Drafting team has made changes to the battery maintenance tables 1-4 (a-f) that does not reflect the extensive re-wording of the Supplemental Reference/FAQ document or address the posted recommendations of IEEE Battery Task Force. The industry needs clear, concise maintenance tasks, intervals and standards for their maintenance programs that are developed and tested by industry experts such as IEEE and EPRI.
Response: Thank you for your comments. The changes to maintenance tables 1-4 (a-f) were made as a result of conversations with members of the IEEE Battery Task Force and their recommendations to the drafting team. The drafting team disagrees with the assertion that the changes to the tables do "not reflect the extensive re-wording of the Supplementary Reference and FAQ document." The drafting team considered the IEEE Battery Task Force Recommendations and revised the Standard with the assistance of several of their members (see the drafting team response posted on the NERC site). The drafting team believes that the Component Attributes, Maximum Maintenance Intervals and Maintenance Activities of Table 1-4 are clear and concise. If an owner has a question concerning how to perform any maintenance activity listed in the table, the Supplementary reference and FAQ document along with IEEE and EPRI documents provide unambiguous and succinct examples of how to perform the activity. This standard is not intended to instruct the Transmission Owners, Generator Owners or Distribution Providers on how to perform the minimum maintenance activates listed in the tables. PRC-005-2 must plainly and tersely tell the owners what they must do - not how to do it.		
American Electric Power	No	The first column, third row of Table 1-2 should be clarified to indicate whether the bulleted items are related by an "or" clause or an "and" clause. For example, must the communication system have either or both of those attributes for it to be considered?
Response: Thank you for your comment. We are requiring both bullets to be applicable and have changed the wording to better reflect our intention.		
ReliabilityFirst	No	ReliabilityFirst offers the following comments related to the bullet points in Question 1:

Organization	Yes or No	Question 1 Comment
		a. Bullet 1 - Agree with definition revisions b. Bullet 2 - Agree with clause 4.2.5.4 c. Bullet 3 - Disagree with revised Table 1-2 “Component Type - Communications Systems.” The revision increased the maximum time for unmonitored systems to 12 years. However, communication failures correspond to one of the top three causes of Misoperations. The revised last row of the Table 1-2 still permits continuous monitoring to be substituted for testing. It is not clear that the available monitoring can actually identify the health of many of the components that can fail in a power line carrier communication system. RFC believes more research is needed to substantiate the 12 calendar year maintenance interval for unmonitored communications systems. d. Bullet 4 - Disagree with revised tables 1-4a, 1-4b, 1-4c, 1-4d, and 1-4f “Component Type - Protection System Station dc Supply....” The changes appear to largely ignore the recommendations of the IEEE Stationary Battery Committee.
Response: Thank you for your comments. A. Thank you. B. Thank you. C. The SDT agrees with your comment and has changed the maximum interval for this activity back to 6 calendar years. D. The changes to maintenance tables 1-4 (a-f) were made as a result of conversations with members of the IEEE Battery Task Force and their recommendations to the drafting team. The drafting team considered the IEEE Battery Task Force Recommendations and revised the standard with the assistance of several of their members (see the drafting team response posted on the NERC site).		
BAE Batteries USA	No	I agree with the basic changes, but recommend that a slight modification be made to Tables 1-4(a) and 1-4(b). In the box defining the 18 calendar Months or 6 Calendar Years, the portion in parentheses (e.g. internal ohmic values or float current) should be changed to (e.g. internal ohmic values or

Organization	Yes or No	Question 1 Comment
		float current in concert with other accepted measurements).
Response: Thank you for your comments. The drafting team disagrees and believes that examination of other accepted measurements and inspection results (indicative of battery performance) are a part of trending to the station battery baseline. This same inference applies to the interpretation of the results of a performance or modified performance capacity test for determining whether a station battery should be replaced or cells removed. Please see section 15.4 of the Supplementary Reference and FAQ document for a further discussion of this topic.		
Central Lincoln	No	Central Lincoln agrees with most of the changes except for the change from “as designed” to “as manufactured” in the Station DC supply table. The concern is not high enough to warrant a negative ballot, and we appreciate the difficulty the SDT has had on this issue with IEEE. The “as manufactured” performance may be interpreted as the battery’s capacity when new and fully charged. Of course a properly engineered system will be based on a future aged battery capacity, reduced from the brand new capacity. We prefer “as designed,” but this might lead a CEA to ask for design documentation an entity may have not retained. In the end, it is not the manufactured or design capacity that matters, it is the battery’s ability to power the protection systems and trip the breakers. We suggest “as manufactured” be changed to “as needed.”
Response: Thank you for your comment. One of the reasons that “as designed” was changed to “as manufactured” is as you discussed. If “as designed” is used it will be difficult for the owner to determine the original design for the dc system, making it difficult for an owner during an audit. Just like the term “as designed” is difficult to document, “as needed” will also be harder for the owner to document than “as manufactured.” See question “Why is it necessary to verify the battery string can perform as manufactured?” in Section 15.4 of the Supplementary Reference and FAQ document for a further explanation of this change.		
EPRI	No	1. Table 1-4a - Verify that the station battery can perform as manufactured by evaluating the measured cell/unit internal ohmic values against the baseline values of each cell.-and-Verify that the station battery can perform as manufactured by conducting a performance capacity test of

Organization	Yes or No	Question 1 Comment
		the entire battery bank. 2. Table 1-4b - Verify that the station battery can perform as manufactured by evaluating the measured cell/unit internal ohmic values against the baseline values of each cell.-or-Verify that the station battery can perform as manufactured by conducting a performance capacity test of the entire battery bank. 3. Table 1-4c - Verify that the station battery can perform as manufactured by evaluating the measured cell/unit internal ohmic values against the baseline values of each cell.-and-Verify that the station battery can perform as manufactured by conducting a performance capacity test of the entire battery bank.
Response: Thank you for your comments: 1. The standard drafting team believes the “or” of table 1-4(a) should not be replaced with the “- and -” as stated in your comment. The station battery owner of a VLA battery should be allowed to perform either of the two maintenance activities listed in table 1-4(a) to be compliant with the standard, and that “cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current)” should remain in the standard. 2. The standard drafting team agrees that the “-or-”should remain as you suggested in your comment. This will allow the owner of a VLRA battery to choose compliance by performing either of the two maintenance activities at their maximum maintenance intervals listed in table 1-4(b). 3. Because of the marked difference in the aging process of lead acid and nickel-cadmium station batteries the drafting team does not believe that trending ohmic values against the baseline values of each cell, and conducting a performance capacity test of the entire battery bank is the appropriate maintenance activity for NiCad Batteries to ‘Verify’ that the station battery can perform as manufactured. The only appropriate maintenance activity in Table 1-4(c) at the maximum maintenance interval of 6 calendar years is to “Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.”		
Illinois Municipal Electric Agency	No	Illinois Municipal Electric Agency supports comments submitted by Florida Municipal Power Agency. IMEA appreciates SDT efforts, and supports the overall refinements in PRC-005-2; however, the inconsistency between 4.2.1 and the FERC-approved interpretation of PRC-005-1b needs to be resolved

Organization	Yes or No	Question 1 Comment
		to avoid confusion. This issue has implications for smaller entities in particular.
Response: Thank you for your comments. The SDT believes that the Applicability 4.2.1 as stated in PRC-005-2 is correct and supports the reliability of the BES. The SDT believes all Protection Systems installed for the purpose of detecting faults on the BES need to be maintained per the requirements of PRC-005-2. The SDT observes that the approved Interpretation addresses the term, "transmission Protection System", and notes that this term is not used within PRC-005-2; thus the Interpretation does not apply to PRC-005-2. Please see Section 2.3 of the Supplementary Reference and FAQ document for additional discussion.		
PPL Generation, LLC on behalf of its Supply NERC Registered Entities	No	See Question 3 Comments
Response: Thank you for your comments. Please see the response to your Question 3 comments.		
TPI	No	See IEEE Stationary Battery Committee Letter dated 23 March 2012
Response: Thank you for your comments. The drafting team considered the IEEE Battery Task Force Recommendations and revised the standard with the assistance of several of their members (see the drafting team response posted on this project's page of the NERC website).		
Tennessee Valley Authority	No	
MRO NSRF	Yes	While we agree with the changes made, we believe that table 1-4 should include in the 18 calendar month maintenance activities: 1) Setting the battery charger to equalize, and 2) Inspect battery charger components for leakage and or damage. These additional steps would verify the ability of the battery charger to operate as needed.
Response: Thank you for your comments. Because all battery chargers used in Protection Systems do not have equalize settings or have components that leak, the drafting		

Organization	Yes or No	Question 1 Comment
team does not believe your recommendation is appropriate for this standard.		
Southern Company	Yes	Related to the changes identified in the Battery Tables: 1. We do not see that the change from "as designed" to "as manufactured" really changed the meaning of the battery capability to delivery its rated capacity. We would like the SDT to consider the following language: "verify that the station battery can provide adequate power to the Protection System by conducting....." 2. For Generating Plant Batteries, we feel as though that the only way to prove that a generation battery can deliver what it is supposed to be able to deliver for "All" of its functions is by conducting a capacity test". We would like the SDT to consider adding such a Note to the battery tables and/or make the statement in the FAQ document.
Response: Thank you for your comments: 1. To "verify that the station battery can provide adequate power" for a battery serving a generating station dc supply or a station dc supply that has dc loads considerably greater than the Protection System requirements may appear to be a good choice; however, the use of "adequate power" makes it difficult for the Generator Owner to determine the original design of the dc system and show an auditor that "adequate power" can be delivered to the dc system by the battery. For this reason and others explained in the Supplementary Reference and FAQ document under the question "why is it necessary to verify the battery string can perform as manufactured?" The drafting team believes that perform as "manufactured" is the best wording for the standard. 2. Your concerns about large amp-hour batteries used in generating stations and transmission stations with large auxiliary loads was addressed in the drafting team's response to the Chair of the IEEE Stationary Battery Committee, which stated: "In contrast to the Transmission Owner battery design function, a Generator Owner's battery likely feeds other critical loads such as DC powered oil pumps, seal oil pumps, and other DC control power loads necessary to safely shutdown a power plant following a loss of AC power. In the case of nuclear plants, these DC loads could include motor operated valves and other loads related to nuclear safety. For the Generator Owner, the design load profile for the battery is a long duration, deep discharge of the battery. While a cell ohmic value trending program might be adequate to prove that the Generator Owners battery could fulfill its Protection System function, the Generator Owner might want to		

Organization	Yes or No	Question 1 Comment
validate the deep discharge capability of the battery by routine periodic capacity testing to prove the battery's adequacy at providing power to those long duration loads critical for plant shutdown. The PSMTSDT believes that this deep discharge battery capacity test approach will prove the battery can meet its function relative to the plant Protection System without also having a trending program for cell ohmic values."		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP agrees that the changes described above make PRC-005-2 clearer and less ambiguous. We believe that this will result in far fewer violations related to administrative or documentation errors - and focus on those cases which actually may impair BES reliability.
Response: Thanks for your support.		
San Diego Gas & Electric	Yes	TABLE 1-5: Similar to the distributed under-frequency load-shedding relays, SPS control circuitry should only be regulated to verify the integrity of the control circuits from the relay to the lockout or auxiliary relay that is used to trip the circuit breakers, but not to the circuit breakers themselves. Owners of SPS control circuitry should have the option of testing these schemes using test procedures that will confirm the control circuitry through the completed trip circuit is continuous and that the circuit breaker will operate when required. Often times the operation of the circuit breaker is confirmed by operation through other protection systems and the SPS function is a parallel path that can be verified without operating the circuit breaker. This change would allow the Transmission Owner to eliminate equipment outages required to test this scheme or the risk caused by removing the SPS for energized testing.
Response: Thank you for your comments. The table only requires that the SPS control circuit path including the trip coil of the breaker be verified with a 12 year maximum interval. The testing does not have to be done all at once; the maintenance activities in the table can be performed in segments and are complete as long as the entire circuit is tested within the interval. Section 10 of the Supplementary Reference and FAQ document provides additional discussion on this.		
Alliant Energy	Yes	While we agree with the changes made, we believe that Table 1-4 should

Organization	Yes or No	Question 1 Comment
		include in the 18 month maintenance activities more checks on Battery Chargers. Based on EPRI data and vendor recommendation we believe that 1) Setting the Battery Charger to equalize, and 2) Inspect battery charger components for leakage and/or damage should be added. These additional steps would better verify the ability of the battery charger to operate as needed.
Response: Thank you for your comments. Because all battery chargers used in Protection Systems do not have equalize settings or have components that leak, the drafting team does not believe your recommendation is appropriate for this standard.		
Ameren	Yes	We believe that the SDT has improved the definitions with these changes and we fully support them. In addition, we also support the Table 1-2 Communication Systems changes based on our experience, and the Station dc Supply changes in the five Tables 1-4a, 1-4b, 1-4c, 1-4d, and 1-4f because they are realistic and consistent with our experience.
Response: Thank you for your support.		
Public Service Company of New Mexico	Yes	1. PNM seeks clarification on the revised Clause 4.2.5.4 of the Applicability section of the standard. - "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." Will Auxiliary Transformers that are directly connected to the generator bus of generators which are part of the BES and that step down to distribution level voltage & perform similar functions as that of station service transformer fall under this clause?
Response: Thank you for your comments. If the cited Protection Systems trip the generator, they are applicable to the requirements of PRC-005-2 and maintained accordingly.		
Brazos Electric Power Cooperative	Yes	Please see the formal comments submitted by ACES Power Marketing.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. Please see the response to ACES Power Marketing.		
Northeast Power Coordinating Council	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Duke Energy	Yes	
Southwest Power Pool NERC Reliability Standards Development Team	Yes	
FirstEnergy	Yes	
Dominion	Yes	
PNGC Small Entity Comment Group	Yes	
Luminant	Yes	
Colorado Springs Utilities	Yes	
Nebraska Public Power District	Yes	
PacifiCorp	Yes	
Independent Electricity System Operator	Yes	
Public Utility District No. 1 of	Yes	

Organization	Yes or No	Question 1 Comment
Okanogan County		
Manitoba Hydro	Yes	
Consumers Energy	Yes	
Georgia Transmission Corporation	Yes	
CenterPoint Energy	Yes	
Seminole Electric Cooperative, Inc	Yes	
Tacoma Power	Yes	
Idaho Power Company	Yes	
American Transmission Company, LLC	Yes	
US Bureau of Reclamation	Yes	
Oncor Electric Delivery	Yes	
Xcel Energy	Yes	
Kansas City Power & Light	Yes	
HHWP		no comment

2. The SDT made complementary changes in the "Supplementary Reference and FAQ Document" to provide supporting discussion for the Requirements within the standard. Do you have any specific suggestions for further improvements?

Summary Consideration:

Commenters suggested a variety changes to the Supplementary Reference and FAQ document. The SDT appreciated the feedback and made numerous modifications to the document ranging from correcting typographical errors to including some additional FAQ and corresponding answers, as well as presenting new and revised technical content.

Organization	Yes or No	Question 2 Comment
San Diego Gas & Electric	No	R5/M5: M5 should add "The evidence may include but is not limited to...tracking of the unresolved maintenance issue in accordance with the TO's corrective maintenance process." This alleviates the Transmission Owner from setting up a separate corrective maintenance tracking process intended solely for this regulation.
Response: Thank you for your comments. This comment is related to the standard itself and not to the Supplementary Reference and FAQ document. The Measures are intended to provide examples of evidence, and are not meant to be all-inclusive.		
Illinois Municipal Electric Agency	No	Illinois Municipal Electric Agency supports comments submitted by Florida Municipal Power Agency.
Response: Thank you for your comments. Please see the responses to Florida Municipal Power Agency's comments.		
PPL Generation, LLC on behalf of its Supply NERC Registered Entities	No	See Question 3 Comments
Response: Thank you for your comment. Please see the responses to your Question 3 comments.		
Northeast Power Coordinating Council	No	
Imperial Irrigation District (IID)	No	

Organization	Yes or No	Question 2 Comment
Duke Energy	No	
Southwest Power Pool NERC Reliability Standards Development Team	No	
Tennessee Valley Authority	No	
Colorado Springs Utilities	No	
Nebraska Public Power District	No	
PacifiCorp	No	
Ingleside Cogeneration LP	No	
Independent Electricity System Operator	No	
Public Utility District No. 1 of Okanogan County	No	
Manitoba Hydro	No	
CenterPoint Energy	No	
Seminole Electric Cooperative, Inc	No	
Tacoma Power	No	

Organization	Yes or No	Question 2 Comment
Idaho Power Company	No	
Kansas City Power & Light	No	
Bonneville Power Administration	Yes	BPA requests the drafting team to provide more detailed examples of the following for both monitoring and testing: 1. That addresses the multiple routes, and automated switching between the routes, in a typical large Telecommunications Network Cloud. This applies only if testing of the 'cloud', or a teleprotection channel through the 'cloud', is the intent of the standard. 2. That addresses the fact that many older teleprotection technologies, not only used separate test inputs/outputs, but the internal path through the equipment is unverified until the particular function is activated. I.E.: In certain technologies, a functioning 'guard' signal does not have any correlation to a functioning 'trip' signal.
Response: Thank you for your comments. 1. The intent of the standard is to verify the teleprotection channel is functional, regardless of what constitutes the channel. 2. The SDT believes that the maintenance activity in Table 1-2, "Verify operation of communication system inputs and outputs that are essential to proper functioning of the Protection System" allows the entity flexibility to maintain the various technologies that they may own. The Supplementary Reference and FAQ document addresses some of the options available, but obviously cannot provide detail on all types of equipment.		
ACES Power Marketing Standards Collaborators	Yes	Several capitalized terms in the supplementary reference document are used inconsistently with their definition or the reference to their definition is not clear. For example, "communications Systems" in the second bullet in section 2.2 uses "Systems" inconsistently with its definition. The use of "sensing Element" on page 6 is another example. We believe this is inconsistent with the definition of Element which could be a generator, transformer, circuit breaker, bus section, etc. but does not appear to be a Protection System Component. The "localized" definition of Component that is contained in the standard should also

Organization	Yes or No	Question 2 Comment
		be included in the reference document since it is not in the NERC Glossary. Use of "dc Load" on page 82 is not consistent with the definition of Load. Load is an end use customer. There are many other places in the document where there are inconsistencies with these definitions. Thus, the document needs to be further reviewed to ensure the use of the terms is consistent with their definitions.
Response: Thank you for your comments. The SDT modified the Supplementary Reference and FAQ document as you suggested.		
Dominion	Yes	The term 'Underfrequency' is capitalized in the Supplementary Reference document yet it is not included in NERC's Glossary of terms. We suggest a return to lower case. In fact, given this document is meant to be used for reference only, we question the need to capitalize any term.
Response: Thank you for your comments. The SDT modified the Supplementary Reference and FAQ document as you suggested. For consistency with the standard, the SDT will continue to capitalize terms when they are used in the context defined in the NERC Glossary of Terms.		
Luminant	Yes	The testing of non-BES breakers for plants should be discussed in the FAQ using the similar application for Distribution Providers. Luminant recommends a section for Generation Owners that describes what Elements (circuit breakers) should be tested. Luminant strongly believes that there is no additional benefit to the BES by requiring the GO to test the non-BES breakers (UAT low side and generator field breakers). These circuits are radial fed.
Response: Thank you for your comments. The FAQ discussion on testing of non-BES breakers for Distribution Providers pertains to those devices used as part of UFLS or UVLS schemes. Section 15.3.1 of the Supplementary Reference and FAQ document has been augmented to address this topic for Generator Owners.		
Southern Company	Yes	See comment on Generating Plant Batteries in Question #1.
Response: Thank you for your comments. Please see the response to your comments in Question 1.		
Western Area Power	Yes	Western Area Power Administration is appreciative of the hard work done by the SDT

Organization	Yes or No	Question 2 Comment
Administration		and NERC. We respectfully submit that the Supplementary Reference and FAQ Document should: 1. Offer guidance on establishing baselines for older battery banks 2. Be in agreement with IEEE standards for battery maintenance 3. Replace the existing CANS
Response: Thank you for your comments. 1. Please see Section 15.4.1 of the Supplementary Reference and FAQ document, specifically the question, "How is baseline established for cell/unit internal ohmic measurements?" which offers guidance on establishing baselines for older battery banks. 2. The IEEE documents to which you refer are "Recommended Practices" as explicitly stated in their titles and not mandatory standards. The SDT considered the IEEE Recommended Practices, as well as other documents, in developing the minimum requirements and maximum intervals within PRC-005-2. 3. The CANs are developed by NERC Compliance Staff to address specific currently-approved NERC Standards, and will be retired when the related standards are retired. The SDT has no control or influence regarding CANs.		
Alliant Energy	Yes	Section 15.4 of the FAQ document does an excellent job of describing the details of battery maintenance and testing, but there is essentially no description of battery charger maintenance and testing activities. We believe this section needs to be expanded to include a good description of battery charger maintenance activities as well.
Response: Thank you for your comments. While manufacturers' recommendations for maintenance of their equipment are quite diverse, the required maintenance activities within PRC-005-2 for battery chargers are: verification of the station dc supply voltage (maximum unmonitored maintenance interval 4 calendar months); and, verification of the battery charger float voltage (maximum unmonitored maintenance interval of 18 calendar months). If anomalies regarding the battery charger are found by performing these activities, relevant corrective actions should be taken.		
American Electric Power	Yes	Rather than voluminous supplementary references, we suggest adding this information, as necessary, to the standard itself. Not only would this prove beneficial by having less information housed outside of the standard, it might also help prevent

Organization	Yes or No	Question 2 Comment
		the need for future CANs and interpretation requests. Though the guidance provided in these documents may appear to be beneficial, we are troubled that the SDT feels it is necessary to provide such a volume of material outside the standard itself, and yet still consider such “references” as enforceable.
Response: Thank you for your comments. This document provides supporting discussion, but is not part of the standard and not enforceable. The SDT intends that it be posted as a reference document accompanying the standard. As established in the SDT Guidelines, the standard is to be a terse statement of requirements, and is not to include explanatory information like that included in the Supplementary Reference and FAQ document. The Supplementary Reference and FAQ document will be revised in conjunction with any revisions of PRC-005.		
BAE Batteries USA	Yes	1. On page 21 of 97,Question 7.1, "Please provide an example of the unmonitored versus other levels of monitoring available," "Every six calendar years, perform/verify the following: Battery performance test (if ohmic tests are not opted)" - add after ohmic tests "or other accepted battery measurement parameters." 2. pg 22 of 97, Example 2 "Every 18 calendar months": Add the same verbiage so that the first bullet reads: "Battery ohmic values or other accepted battery measurement parameters to station battery baseline . . ." 3. pg 23 of 97, Example 3 "Every 18 calendar months": Add the same verbiage so that the first bullet reads: "Battery ohmic values or other accepted battery measurement parameters to station battery baseline . . ." 4. pg 23 of 97, Example 3 "Every six calendar years": Add the same verbiage so that the first bullet reads: "(if internal ohmic test or other accepted battery measurement parameters to station battery baseline are not opted)" 5. pg 27 of 97, Question 8.1.2, item #4: Change the last sentence to read: "However, the methods prescribed in these recommendations cannot be specifically required because they are offered as best practice guidelines and not set as standards." 6. pg 71 of 97, Question 15.4.1, Frequently asked Questions: "How is a baseline

Organization	Yes or No	Question 2 Comment
		established for cell/unit internal ohmic measurements?" 2nd paragraph - 1st sentence, replace the word "consistent test equipment" with "the same type of test equipment." In addition, should add a final sentence at the end of this paragraph that states, "Also, in many cases, one manufacturer's 'conductance' test may not produce the same measurement results as another 'conductance' test manufacturer's equipment. Therefore, for meaningful results to an established baseline, the same instrument should always be used." 7. Page 73 of 97, Question 15.4.1, Frequently asked questions: "What conditions should be inspected for visible battery cells?" Approximately in the 7th line modify the sentence to read . . .abnormal color(which is an indicator of sulfation or possible copper contamination) . . . 8. Page 75 of 97, Question 15.4.1, Frequently asked questions: "How do I verify the battery string can perform as manufactured?" 2nd paragraph that reads "Whichever parameter is evaluated . . ." should be revised to say "Whatever parameters are used to evaluate the battery (ohmic measurements, float current, float voltages, specific gravity, performance test, or combination thereof), the goal is to determine . . . 9. Page 75 of 97, Question 15.4.1, Frequently asked questions: "How do I verify the battery string can perform as manufactured?" 5th paragraph starts, "A detailed understanding of the characteristic of a battery is also attempting to use float current as a measure of the ability of a battery . . . and ends with "to see if a trending process is recommended for determining aging of these products." The Stationary Battery Task Force recommends deleting this whole paragraph due to inaccuracies or statements that are not relevant. If a paragraph that alludes to float current is considered critically essential, then a short paragraph could be substituted which might say," Float current along with other measureable parameters can be used in lieu of or in concert with ohmic measurement testing to measure the ability of a battery to perform as manufactured. The key to using any of these measurement devices is to establish a trending line against baseline so that a documented process establishes the validity of the judgment used to determine that the battery may

Organization	Yes or No	Question 2 Comment
		perform or not perform as manufactured." 10. Page 81 of 97, Question 15.4.1, Frequently asked questions: "Why does it appear that there are two maintenance activities in Table 1-4(b) for VRLA batteries . . . .?" 3rd paragraph: "A comparison and trending against the baseline new battery ohmic reading can be used in lieu of capacity tests to determine remaining battery life. Remaining battery life is analogous to stating that the battery is still able to 'perform as manufactured.'" This might better be restated as follows: "Trending against the baseline of VRLA cells in a battery string is essential to determine approximate state of health of the battery. For example, using ohmic measurement testing as the mechanism for measuring the battery cells, then, if all the cells in the string show to be in a consistent trend line and that trend line has not risen above say a 25-30% deviation over baseline, then a judgment can be made that the battery is still in a reasonably good state of health. This judgment can assume that the battery is still able to 'perform as manufactured.' It would be wise to confirm the accepted deviation range with the manufacturer of the battery in question to assure good judgment in deciding on the state of health to perform as manufactured.' This is the intent of the "perform as manufactured six-month test' at Row 4 on Table 1-4(b)." 11. Page 81 of 97, Question 15.4.1, Frequently asked questions: [same as Item #10 above], following paragraph: Recommend using a range of 25-30% with the statement that "It would be wise to confirm the accepted deviation range with the manufacturer of the battery in question to assure good judgment' in deciding on the state of health to perform as manufactured.

Response: Thank you for your comments.

1. The SDT modified the Supplementary Reference and FAQ document on page 21 as you suggested.
2. The SDT modified the Supplementary Reference and FAQ document on page 22 as you suggested.
3. The SDT modified the Supplementary Reference and FAQ document on page 23 as you suggested.
4. The SDT modified the Supplementary Reference and FAQ document on page 23 as you suggested.
5. The drafting team agrees with your comment concerning all of the best practices of the IEEE guidelines not being requirements of the standard and incorporated your comments into the Supplementary Reference and FAQ document on page 27.

Organization	Yes or No	Question 2 Comment
6. The drafting team incorporated your comments concerning same type test equipment replacing consistent type test equipment on pages 71 & 72 of the Supplementary Reference and FAQ document. 7. The drafting team added a comment regarding color observation on page 74 of the Supplementary Reference and FAQ document. 8. The SDT modified the Supplementary Reference and FAQ document on page 75 as you suggested. 9. The SDT modified the paragraph on float current on page 75 of the Supplementary Reference and FAQ document as you suggested. 10. The SDT modified the Supplementary Reference and FAQ document based on your comment. 11. The SDT revised the Supplementary Reference and FAQ document as you suggested.		
Georgia Transmission Corporation	Yes	Recommend adding further comments on data retention. We prefer the interpretation for the maintenance cycles equaling 12 calendar years, example microprocessor protective relays. This proves the extreme of data retention. We interpret the retention period to be 24 years. Previous test record to current test record equals 12 years, and 12 more years (next maintenance cycle) before removing previous records from storage (24 years).
Response: Thank you for your comments. To be assured of compliance, the SDT believes the Compliance Monitor will need the data for the most recent performance of the maintenance, as well as the data for the preceding maintenance period. This seems to be consistent with what auditors are expecting (per the SDT's experience), and is also consistent with Compliance Process Bulletins 2011-001 and 2009-05.		
Ameren	Yes	(1) Capitalizing in some cases is inappropriate (e.g., Systems; Glossary defines System as 'A combination of generation, transmission, and distribution components.' So 'communication System' incorrectly capitalizes 'system'). (2) Page 15, we disagree with retention of maintenance records for replaced equipment as this can cause confusion. We believe that at the most the last maintenance date could be retained to prove interval between it and the test date of the replacement equipment that provides like-kind protection. (3) We request the SDT to provide a few examples of 'non-battery-based dc supply'. The SDT has previously responded that this does not include 'capacitor trip devices'.

Organization	Yes or No	Question 2 Comment
		Does the SDT mean to include M-G sets, flywheels, and / or rectifiers? Also, Emerging Technologies on page 73 is vague please clarify.
Response: Thank you for your comments. 1. The SDT revised the Supplementary Reference and FAQ document to address your comment. 2. The records for removed/replaced equipment need to be retained to provide documented evidence that the entity was in compliance for the entire compliance monitoring period. This documentation includes maintenance activities as well as maintenance intervals. 3. As noted, the drafting team previously stated that the "capacitor trip devices" on circuit breakers and reclosers are not examples of station dc supply devices using emerging technology. Some of the non-battery based energy storage devices with demonstrated prototypes for use in Protection System dc supplies are the flywheel and the fuel cell. One non-battery based dc supply commercially available in the United States and Canada uses compressed air and a capacitor to replace the electrochemical process of a station battery for supplying the dc power required for operating Protection System elements and for supplying normal dc power to the station in the event of loss of ac power.		
Public Service Company of New Mexico	Yes	The Supplementary Reference and FAQ Document has served as a valuable resource and PNM commends the drafting team's efforts in writing a comprehensive document. Section 13. Self Monitoring Capabilities and Limitations - Last but one bullet on Page 59 of the Supplementary Reference and FAQ Document is confusing and needs possible rewording and clarification. "With this information in hand, the user can document monitoring for some or all sections by extending the monitoring to include..." appears confusing.
Response: Thank you for your comments. The SDT modified the Supplementary Reference and FAQ document to address your comment.		
EPRI	Yes	Why consider the ability of the station battery to perform as manufactured? The reason the term "perform as manufactured" was used is because there is not much data available to verify actual sizing of the cells for their application. The only battery values for typical Protection systems that have a verifiable basis are the battery manufacturer's data. The only way to know when a battery needs to be replaced is to

Organization	Yes or No	Question 2 Comment
		compare measured values against manufacturer's data or other established values. To verify that the station battery can perform as manufactured is the process of determining when the station battery must be replaced or when an individual cell or battery unit must be removed or replaced. Inspections alone do not provide trending information that indicates the state of aging of a station battery. The maintenance activities listed in Table 1-4 to "verify that a station battery can perform as manufactured" are intended to provide information about the aging process of a station battery. A Transmission Owner, Generator Owner or Distribution Provider can then use the information provided by the maintenance activity to determine if testing of a station battery is required or if timely replacement or removal of the station battery or its components (cell/unit) should be accomplished. Capacity discharge testing is the only industry approved method of determining the true capacity of lead acid and nickel-cadmium station batteries. The performance capacity test of the entire battery bank listed as maintenance activities of table 1-4 provides a mechanism for trending battery discharge characteristics based on manufacturers published data. Trending discharge test results is the basis for determining the aging of a station battery serving a Protection System. Based on these results, decisions concerning replacement of a battery serving a Protection System and its components can be made by the Transmission Owner, Generator Owner or Distribution Provider. There is a marked difference in the aging process of lead acid and nickel-cadmium station batteries. The difference in the aging process of the two types of batteries is chiefly due to the electrochemical process of the battery type. Aging and eventual failure of lead acid batteries is due to expansion and corrosion of the positive grid structure, loss of positive plate active material, and loss of capacity caused by physical changes in the active material of the positive plates. However, the primary failure of nickel - cadmium batteries is because of the gradual linear aging of the active materials in the plates. The electrolyte of a nickel - cadmium battery only facilitates the chemical reaction (it functions only to transfer ions between the positive and negative plates), but is not chemically altered during the process like the electrolyte of a lead acid battery. A lead acid battery experiences continued

Organization	Yes or No	Question 2 Comment
		corrosion of the positive plate and grid structure throughout its operational life while a nickel - cadmium battery does not. Changes to the periodic measured properties of a lead acid battery when trended to a baseline can provide an indication of aging of the grid structure, positive plate deterioration, or changes in the active materials in the plate. Since aging in nickel-cadmium cells is linear, periodic measured properties of nickel-cadmium cells when trended to a baseline can provide an indication of aging of the active material in the positive plates. By trending periodic measured properties of a station battery serving its Protection System the Transmission Owner, Generator Owner or Distribution Provider can develop a condition based method to determine (1) when a station battery requires a capacity test (instead of performing a capacity test on a predetermined, prescribed interval), (2) when an individual cell or battery unit should be replaced, or (3) based on the analysis of the trended data, if the station battery should be replaced without performing a capacity test. There is a clear difference in the aging process of lead acid and nickel-cadmium batteries. The measurable properties of a nickel - cadmium battery will change more gradually than VRLA cells; therefore, periodic interval and trending to determine aging has very little industry experience, but the user should work with the battery manufacturer to determine if internal ohmic measurements can be applied to their product. While it has been proven that there is a relationship between internal ohmic measurements and cell capacity of lead acid batteries, an accurate determination of a battery's exact capacity cannot be attained by measuring its cell's internal ohmic values. However, trending internal ohmic measurement of VRLA battery cells to establish a base line is a method of trending measured properties by Transmission Owners, Generator Owners and Distribution Providers to evaluate their station battery cells for health and aging. Evaluating internal ohmic cell/unit measurements against the battery cell baseline values is an acceptable Maintenance Activity listed in tables 4-1(a) and 4-1(b) 4-1(c) to verify that the station battery can perform as manufactured as long as it is measured and trended to the baseline values at an interval less than or equal to the published Maximum Maintenance Interval of tables. Why was the term "manufactured" used instead of "designed" in the maintenance activities of tables 1-

Organization	Yes or No	Question 2 Comment
		4(a), 1-4(b), 1-4(c), 1-4(d) and 1-4(f)?The phrase “as designed” always raises the question of “who made the design requirements that are being tested to or evaluated, the manufacturer of the battery or the engineer sizing the battery? The use of the term designed when discussing a battery’s ability to perform was incorrect because we did not differentiate between a performance test and a service test. The phrase “meets the design requirements” is used when discussing a service test which is a discharge test that measures a battery’s capability to meet a duty cycle which was designed by the person sizing the battery. However, when talking about a performance capacity test, the test is a measure of the currents or amp-hour discharge rates based on the battery manufacturer data for the station battery being tested. The term “manufactured” used in the tables avoids the confusion caused by the term “designed” and its application to service testing. Also, when discussing internal ohmic measurement trending, “manufactured” applies to establishing a set of base line values when compared to a battery of known capacity based on the manufacturer’s published data. When trending other measurable properties that assist in establishing aging, the battery manufacturer’s data are used as a basis for establishment of baseline values and therefore the use of “manufactured” avoids any ambiguity that might be caused by use of the term “designed”.

Response: Thank you for your comments.

The drafting team recognizes that the majority of your comments support and amplify the information contained in the Supplementary Reference and FAQ document. However, the drafting team does not agree with some of the information contained in your comments.

1. While the drafting team agrees that part of the process of determining when to replace a battery should be “to compare measured values against manufacturer’s data or other established values,” we disagree with the statement “the only way to know when a battery needs to be replaced is by using this maintenance activity” because it does not give credit to the role visual inspections play in the replacement process.
2. The drafting team has a broader interpretation of the term “manufactured” than that implied in your comment concerning ohmic measurement trending (“manufacturer’s published data”). We believe the term “manufactured” as used in the maintenance activities of the standard also includes as you stated earlier in your comment “other established values.” Just as

Organization	Yes or No	Question 2 Comment
battery manufacturers establish tolerances that when exceeded constitute further examination of the battery for replacement, test equipment manufacturers, battery owners and others have established tolerances for specific batteries that are considered valid to determine if the particular battery can perform as "manufactured." 3. As implied in your comment and by over a decade of industry experience, it has been proven that there is a relationship between internal ohmic measurements and the aging process of lead-acid batteries. No such relationship has been established for nickel-cadmium batteries. Also at this time - with the exception of the results of a capacity test - the drafting team is unaware of any published data for nickel-cadmium battery properties that can be measured and trended against the station battery baseline. The drafting team believes that either of the two maintenance activities listed in table 1-4(a) and 1-4(b) for lead-acid batteries are acceptable to verify that the station battery can perform as manufactured when conducted at the maximum maintenance intervals of the tables. However, the drafting team disagrees with your inference that table 1-4(c) for Nickel Cadmium batteries should have any other maintenance activity besides the performance or modified performance capacity test of the entire bank to verify that the station battery can perform as manufactured.		
US Bureau of Reclamation	Yes	The FAQ should clarify why the requirement for a "Summary of maintenance and testing procedures" developed by an entity is considered prescribing a methodology to meet those requirements. The entity is developing the methodology for meeting the requirements that the elements be maintained.
Response: Thank you for your comment. "Summary of maintenance and testing procedures" is terminology used in Requirement R1.2 of the existing standard PRC-005-1.1b and is not applicable to version PRC-005-2.		
Oncor Electric Delivery	Yes	On Page 81 of the Supplementary reference and FAQ Draft it appears that the drafting team changed the term "designed" to "manufactured" and then used the quotation from the previous standard's Table 1-4(b). Oncor recommends that the two statements on page 81 of the Supplementary Reference and FAQ - Draft be changed from the present version "...verify that the station battery can perform as manufactured by evaluating the measured cell/unit internal ohmic values to station battery baseline." "Verify that the station battery can perform as manufactured by conducting a performance, service, or modified performance capacity test of the entire battery bank." to a new version of the quotes based on the new version of Table 1-4(b). The new quotes should be stated as follows:"...verify that the station

Organization	Yes or No	Question 2 Comment
		battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.” ”Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.”
Response: Thank you for your comments. The SDT modified the Supplementary Reference and FAQ document based on your comments.		
Brazos Electric Power Cooperative	Yes	Please see the formal comments submitted by ACES Power Marketing.
Response: Thank you for your comment. Please see the responses to the ACES Power Marketing comments.		
Xcel Energy	Yes	The following paragraph from the top of page 71 in the FAQ should be retained. When internal ohmic measurements are taken, consistent test equipment should be used to establish the baseline and used for the future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer’s equipment. Keep in mind that one manufacturer’s “Conductance” test equipment does not produce similar results as another manufacturer’s “Impedance” test equipment, even though both manufacturers have produced “Ohmic” test equipment. This paragraph from page 78 (second full paragraph) should be stricken or re written. Consistency is the key when measuring and evaluating ohmic readings. Consistent testing methods by trained personnel are essential. Moreover, it is absolutely critical that personnel use the same make/model of test instrument every time readings are taken if the values are going to be compared. The type of probe, the location of the reading (post, connector, etc.) and the room temperature during the test needs to be carefully recorded when the readings are taken. For every subsequent time the readings are taken, the same make/model of the test instrument must be used, the same type of probes must be used, and the location of the reading must be the same. The first paragraph explain the consistency issue and the second then removes the ability to

Organization	Yes or No	Question 2 Comment
		use consistent equipment and rather demands that identical equipment be used. This is not a feasible position as manufacturers can and do leave the testing space and therefore the entity should be cognizant of using the appropriate compatible test equipment but to spell out that particular make/models be maintained is not acceptable and brushes against anti-trust complications by inhibiting new players in this testing space.
Response: Thank you for your comments. The SDT revised the Supplementary Reference and FAQ document to address your concerns.		
TPI	Yes	Page 81...this statement is incorrect and should be changed: "A comparison and trending against the baseline new battery ohmic reading can be used in lieu of capacity tests to determine remaining battery life." "can be used" has to be changed to "may be used". This should refer to the other FAQ to fully explain how to use ohmic measurements. Page 81...25% is not a universally accepted value. This value has to be determined by experience for a particular type/model of battery. This part of the FAQ contradicts other FAQs.
Response: Thank you for your comments. 1. The SDT revised the Supplementary Reference and FAQ document based on your comment. 2. The SDT used 25% as an example, and revised the Supplementary Reference and FAQ document for clarity. Since there are no universally accepted repositories of this information, the Protection System owner will have to determine the value/percentage where the battery cannot perform as manufactured. This is the most difficult and important part of the entire process. The paragraph on page 81 of the Supplementary Reference and FAQ document has been modified based on your comments.		
HHWP		no comment
MRO NSRF	Yes	

Organization	Yes or No	Question 2 Comment
FirstEnergy	Yes	
PNGC Small Entity Comment Group	Yes	
Central Lincoln	Yes	
American Transmission Company, LLC	Yes	

3. **If you have any other comments that you have NOT provided in response to the above questions, please provide them here. (Please do not repeat comments that you provided elsewhere.)**

Summary Consideration:

Some commenters continued to object to various activities and/or intervals within the tables. The drafting team made several changes detailed below in response to these comments.

1. One interval was changed – the interval for the activity in Table 1-2 for unmonitored communications systems was changed from 12 years back to 6 years as it had been in all previous postings. This change promotes consistency with similar activities within Table 1-1 (Protective Relays).
2. The language in two activities in Table 1-2 was changed from “channels” to “communications systems”.
3. The language in the Component Attributes in the last row of Table 1-2 was modified to read: “Any communications system with all of the following:” to clarify that all must be present to use the related intervals and activities.
4. In Table 1-4e, a redundant “only” was removed from the Component Attributes in the last row.

A few commenters objected to the prescribed VRFs and/or VSLs. The SDT responded that these VRFs and VSLs are in accordance with guidance from FERC and NERC.

A few comments were offered regarding Data Retention, generally objecting to retaining the maintenance records for two complete maintenance intervals. The SDT responded that the data retention specifications are consistent with auditors’ expectations and with Compliance Process Bulletins 2011-001 and 2009-05.

Several comments were made (some expressed as the reason for a Negative Ballot) in response to the informational posting of the draft SAR to modify PRC-005-2 to add reclosing relays. No changes were made as a result of these comments.

Organization	Yes or No	Question 3 Comment
Ameren		(1) Remove Table 1-4 batteries from the Countable Event definition. (2) Please change Table 1-4(d) title to “Component Type - Protection System Non Battery Based Station dc Supply” [delete: Using Non Battery Based Energy Storage] to be consistent with the definition.

Organization	Yes or No	Question 3 Comment
		(3) R3 & R4: Change VRF to “Medium” for the following reasons: (a) Guideline (3) - Consistency among Reliability Standards is not satisfied. The VRF_Standards_Applicability_Matrix_2012-03-01 clearly shows that comparable requirements in the standards that PRC-005-2 replaces are Medium or Lower, specifically PRC-005-1b R2 VRF is Lower, PRC-008-0 R2 VRF is Medium, PRC-011-0 R2 VRF is Lower, and PRC-017-0 R2 VRF is Lower. (b) The High Risk Requirement is not met. We are not aware that lack of Protection System maintenance alone has directly caused or contributed to bulk electric system instability, separation, or a cascading sequence of failures. (c) Guideline (4) Consistency with NERC’s Definition of the Violation Risk Factor Level is not met. Many entities do not presently perform several of the proposed minimum maintenance activities, and/or perform maintenance activities at greater than the PRC-005-2 maximum interval. Yet BES system instability, separation, or cascading sequence of failure events continues to be extremely rare. (4) Measure M3 on page 6 should only apply to 99.5% of the components. We strongly advocate the SDT to revise and state: “Each ... shall have evidence that it has implemented the Protection System Maintenance Program for 99.5% of its components and initiated....” We believe l that PRC-005-2 unrealistically mandates perfection without providing technical justification. A basic premise of engineering is to allow for reasonable tolerances, even Six Sigma allows for defects. Requiring perfection may well harm reliability by distracting valuable resources from higher priority duties concerning the Protection System. Note that we are not suggesting for the VSL to be changed. Our proposed reasonable tolerance sets an appropriate level of performance expectation. We disagree with the notion that this is “non-performance”.

Response: Thank you for your comments.

1. The SDT believes that R1.1 is very explicit (All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program) and has precedence over the Countable Event definition. However, the

Organization	Yes or No	Question 3 Comment
drafting team does not agree that Table 1-4 should be removed from the Countable Event definition; Table 1-4(d) addresses non-battery-based energy storage devices, which can use a performance based program. 2. The SDT sees no appreciable improvement in the standard with your proposed change and respectfully declines to modify the standard. The drafting team believes the words “Energy Storage” in the title of Table 1-4(d) better conveys the role or circumstance of not having a battery in the dc supply, more so than using the wording from the latest version of the definition of Protection System (non-battery-based dc supply). 3. The SDT believes that the assigned VRFs are correct, as explained below: a. The SDT believes the requirements of PRC-005-2 do not map, one-to-one, with the requirements of the legacy standards, each of which comingle various attributes addressed within the new standard; thus, a requirement – to – requirement comparison of VRFs is irrelevant. b. The SDT believes that failure to implement and follow its PSMP could cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures. c. The SDT believes that failure to implement and follow its PSMP could cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures. **4.** VSLs define the degree to which compliance with a requirement was not achieved. Anything less than 100% constitutes a violation.		
ACES Power Marketing Standards Collaborators		-1- The data retention requirements for Requirements R2, R3, R4, and R5 are not consistent with NERC Rules of Procedure. Section 3.1.4.2 of Appendix 4C – Compliance Monitoring and Enforcement Program states that the compliance audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. The data retention requirements compel the registered entity to retain documentation for the longer of “the two most recent performances of each distinct maintenance activity for Protection System Components, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date”. Given that many of the maximum maintenance intervals exceed audit periods for responsible entities, an entity could be required to retain data previous to its last audit, which is not consistent with the Rules of Procedure. We suggest changing this such that the data only needs to be maintained since the last audit. -2- Under the “Definitions” section, for the definition of “Protection System” it is

Organization	Yes or No	Question 3 Comment
		unclear whether the bullets constitute items that are considered to be Protection Systems, elements that may be included within a Protection System, or elements which all must be included to constitute a Protection System. A statement preceding the bullets that explains their relationship to the term "Protection System" would be helpful. This clarification should at least be made within the supplementary reference document, if it cannot be made to the actual definition. -3- Requirement R1 VSLs: It is not clear why missing three component types jumps to a Severe VSL. Missing two is a Moderate VSL. Missing three should be a High VSL.
Response: Thank you for your comments. 1. To be assured of compliance, the SDT believes the Compliance Monitor will need the data for the most recent performance of the maintenance, as well as the data for the preceding maintenance period. This seems to be consistent with what auditors are expecting (per the SDT's experience), and is also consistent with Compliance Process Bulletins 2011-001 and 2009-05. 2. The definition of Protection System is expressed in the manner that FERC approved on February 3, 2012. 3. The SDT believes that missing three component types is a "significant percentage" and is in accordance with the VSL Guidelines.		
Exelon Corporation and its affiliates		1. In the response to Exelon's previous comment regarding current transformers, the SDT disagreed that test mandated by the current Standard draft seeks to measure a signal is "provided to the protective relay"; however, the test referenced in Table 1-3 merely confirms that the signal is sent and not that it reached the correct protective relay. Generation sites are built in phases, and these requirements do not ensure that the wiring of the protection system matches the prints and the intent of the engineers who designed it. Please provide a technical explanation of how this type of test for a CT will verify that the signal reaches the relay. 2. In the response to Exelon's previous comment related to the maintenance activity in Table 1-3 for PTs and CTs as they relate to electro mechanical relays the SDT disagreed that the maintenance program should be left to the discretion of the Generator Owner. Exelon further explained that In order to meet the required activity specified in PRC-005-2 draft 2 Table 1-3, the generating unit would be required to take readings with meters while the unit is operating. This practice

Organization	Yes or No	Question 3 Comment
		introduces a risk of tripping the unit inadvertently. The risk of tripping the unit while performing this maintenance activity is contrary to the intended purpose of PRC-005 and introduces a potentially adverse effect on the reliability of the BES. In its response the SDT has not provided the justification as to why performing such a high risk activity increases the reliability of the BES and justification for testing that refutes existing manufacturers recommendations. 3. In the last round of comments, the SDT did not specifically address Exelon's comments regarding the omission of "...and trips an interrupting device that interrupts current supplied directly from the BES" from the revised applicability language in Section 4.2.1. We are concerned that the SDT may not fully appreciate our concern. Without the qualification that comes from the "and..." phrase above, Exelon feels that section 4.2.1 will bring reverse-looking relays on radial transformers into scope, which are not interpreted as BES Protection Systems. By doing so, it creates a perverse incentive to disable these protection functions, even though they provide a reliability benefit, for the sake of limiting compliance exposure. Please offer a direct response to why the phrase, "...and trips an interrupting device that interrupts current supplied directly from the BES" is no longer included in 4.2.1 and clarify that non-BES relays are not considered within scope. Comments and SDT Response from last comment period (for reference):Exelon Comment: When the SDT changed the original PRC-005 applicability language from "...affecting the reliability of the BES..." to the new 4.2.1 language "...that are installed for the purpose of detecting faults on BES elements (lines, buses, transformers, etc.)", they opted to exclude the second half of this sentence taken from the PRC-005-1a Interpretation, which read "...and trips an interrupting device that interrupts current supplied directly from the BES." By doing so, the SDT failed to recognize that some Protection Systems can be responsive to faults on the BES, but still have no effect on the reliability of the BES. The change in 4.2.1 may unintentionally expand the scope of PRC-005.Depending on how Section 4.2.1 is interpreted, it could create a perverse incentive to disable, or not apply, reverse directional protection on the secondary (at voltages less than 100kV) of radially connected load-serving transformers. Such

Organization	Yes or No	Question 3 Comment
		relaying typically uses available units in a multifunction device, and while not critically necessary for fault clearing, it is applied because it adds a benefit at no incremental cost with minimal security risk, and it will not interrupt a BES element if it operates insecurely. It also improves reliability to connected distribution load, in the event a BES transmission line faults during abnormal switching, by coordinating with non-directional overcurrent relays that would otherwise interrupt the entire load. Furthermore such directional relaying would only operate after the faulted BES line is already removed from any connection at BES voltages via its high voltage (>100kV) circuit breakers. Viewed in an expansive way, the proposed 4.2.1 language could bring into scope these relays as well as tripping circuits of distribution voltage circuit breakers that are normally operated in a radial configuration. It would be reasonable for a TO to disable this relaying, rather than accept these consequences. In the previous comment period (Sept 2011), industry raised similar concerns and to most of the commenters, the SDT responded with the following statement: " The SDT believes that the Applicability as stated in PRC-005-2 is correct and that it supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term, "transmission Protection System", and notes that this term is not used within PRC-005-2; thus the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses "Protection Systems that are installed for the purpose of detecting faults on BES Elements." Please see Section 2.3 of the Supplementary Reference and FAQ document for additional discussion." Unfortunately, this response fails to address the concerns raised above. Entergy previously suggested the following language for 4.2.1:"Protection Systems that are installed for the purpose of detecting faults on BES Elements (lines, buses, transformers, etc.) and trips an interrupting device that interrupts current supplied directly from the BES Elements." This language is appropriate and addresses industry concerns. We ask that the SDT adopt this language as Section 4.2.1. SDT Response: The SDT believes that the Applicability, as stated in PRC-005-2, is correct and supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term, "transmission Protection System," and notes that this term is not used within PRC-005-2; thus, the

Organization	Yes or No	Question 3 Comment
		interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses “Protection Systems that are installed for the purpose of detecting Faults on BES Elements.” Please see Section 2.3 of the Supplementary Reference Document for additional discussion. Thank you for the opportunity to comment.
Response: Thank you for your comments. 1. Section 15.2 of the Supplementary Reference and FAQ document provides a technical explanation of how this type of test for a CT will verify the signal reaches the relay. 2. The SDT believes it is possible during a 12-year interval to find a reasonably low-risk opportunity to perform the required test and that performing the test satisfies FERC Order 693 “…that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk Power System.” Please see Section 15.2.1 of the Supplementary Reference and FAQ document for examples of off-line tests that can minimize the risk you describe. **3.** Reverse-looking relays (in the cited application) are not installed for the purpose of detecting faults on the BES and would not be subject to this standard. The SDT believes that the Applicability as stated in PRC-005-2 is correct and that it supports the reliability of the BES.		
Southern Company		1. We would like the SDT to consider rewording M5 as follows: The evidence may include any form of evidence indicating an entity is demonstrating efforts to correct identified Unresolved Maintenance Issues. Additionally: All of the examples of evidence should be moved to the Supp Ref doc and be there only for reference. 2. Page numbers should be visible on all pages.
Response: Thank you for your comments. 1. The SDT does not believe that the changes you suggest improve the standard. Regarding “demonstrate efforts to correct…,” the SDT’s intent is to allow an entity to furnish a way of addressing Unresolved Maintenance Issues without the formality and burden of a full-fledged Corrective Action Plan. 2. The SDT agrees and has referred the concern to NERC Staff for their consideration when preparing the documents for posting.		
Ingleside Cogeneration LP		Although Ingleside Cogeneration LP does not want to derail the improvements that the SDT has obviously made to PRC-005-1, we remain concerned that expansions in

Organization	Yes or No	Question 3 Comment
		scope of a BES Protection System will automatically roll over to other standards. For example, if the loss of a low voltage auxiliary transformer can trip a generator, its Protection System will be in-scope for PRC-005-2. It is not a big leap in logic to assume that the auxiliary transformer itself should be a BES Element - and subject to the whole body of CIP, MOD, IRO, and TOP standards. Our experience has been that Compliance authorities will make these assumptions, even if that was never the intent of the SDT. The effort to develop and maintain procedures, test results, and communications concerning every BES Element is not trivial - and a single instance of a missed requirement may lead to fines in the thousands of dollars. Ingleside Cogeneration is committed to take any action required to assure BES reliability, but NERC and the project teams must have evidence of its own that it is worth the cost.
Response: Thank you for your comments. The SDT believes that performing these maintenance activities will benefit the reliability of the BES.		
American Electric Power		1. As stated in our previous comments for R3, Table 1-5 notes a “mitigating device” as part of component attributes. The meaning of this phrase is open to interpretation and needs to be clearly defined. Is it a discrete device? A protection scheme? Either? The team’s response, by stating its intentions regarding this phrase, actually illustrates the need to provide clarity for this term within the standard. 2. As stated previously, under the time-based maintenance method and R3, the Entity will be required to utilize the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. Special Protection Systems, by their nature, may physically include components that are not listed in the NERC definition of Protection System and therefore are not included in the tables of PRC-005-2. The standard, as currently drafted, does not clearly provide a means for an Entity with a Special Protection System to establish both minimum maintenance activities and maximum maintenance intervals for components that have been declared by their Region as part of a Special Protection System but that are *not* included in the NERC definition of Protection System. For example, consider a Special Protection

Organization	Yes or No	Question 3 Comment
		System that is comprised of the following elements: Generating Unit Distributed Control System (DCS) - Qty 1Protective Relays - Qty 4 - Provide digital inputs to DCS Boiler Pressure Transmitters - Qty 2 - Provide analog inputs to DCS For a predetermined set of system events, the protective relays operate, indicating to the DCS that the event has occurred. If the pressure transmitters indicate that the boiler pressure exceeds a predefined threshold, the DCS responds by adjusting the analog output signals to the turbine valves. For compliance with the existing version of PRC-017-0, the owner of the above system has written a Maintenance and Testing Program that thoroughly tests the protective relays, DCS logic and analog inputs and outputs. However, under PRC-005-2, the owner of the system would not be able to use the proposed performance based method because the system does not have the required Segment population of 60 components. This leaves the owner no other option than the time based method. However, only the protective relays meet the NERC definition of Protection System and they are the only elements of this hypothetical SPS described in Tables 1-1 through 1-5. The existing PRC-005-2 draft does not contain time based activities that would be applicable to the DCS logic, analog inputs and analog outputs. Therefore, whereas the existing NERC standards demand the testing of these devices, NERC standards would no longer require their testing upon the implementation of PRC-005-2.
Response: Thank you for your comments. 1. A mitigating device is one that acts to respond as directed by a Special Protection System (SPS). It may be a breaker, valve, distributed control system, or any variety of other devices. 2. The SDT notes that the definition of a Special Protection System states “An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability.” If the SPS you described meets this definition and contains Protection System components, then PRC-005-2 applies to those Protection System components.		
American Transmission Company, LLC		ATC recommends that the SDT change the text of “Standard PRC-005-2 - Protection System Maintenance” Table 1-5 on page 24, Row 1, Column 3” to: “Verify that a trip

Organization	Yes or No	Question 3 Comment
		coil is able to operate the circuit breaker, interrupting device, or mitigating device." Or alternately, "Electrically operate each interrupting device every 6 years." Basis for the change: Trip coils are designed to be energized no longer than the breaker opening time (3-5 cycles). They are robust devices that will successfully operate the breaker for 5,000-10,000 electrical operations. In addition, many utilities purchase breakers with dual redundant trip coils to mitigate the possibility of a failure. It is well recognized that the most likely source of trip coil failure is the breaker operating mechanism binding, thereby preventing the breaker auxiliary stack from opening and keeping the trip coil energized for too long of a time period. Therefore, trip coil failure is a function of the breaker mechanism failure. Exercising the breakers and circuit switchers is an excellent practice to mitigate the most prevalent cause of breaker failure. ATC would encourage language that would suggest this task be done every 2 years, not to exceed 3 years. Exercising the interrupting devices would help eliminate mechanism binding, reducing the chance that the trip coils are energized too long. The language, as currently written in Table 1-5 row 1, will also have the unintentional effect of changing an entities existing interrupting device maintenance interval (essentially driving interrupting device testing to a less than 6 year cycle).ATC continues to recommend a negative ballot since we believe that the testing of "each" trip coil will result in the increased amount of time the BES is in a less intact system configuration. ATC hopes that the SDT will consider these changes.
Response: Thank you for your comments. The SDT sees no appreciable improvement in the standard with your proposed change and respectfully declines to make the modification.		
Colorado Springs Utilities		Colorado Springs Utilities votes "negative" based on the document "Draft SAR for Phase 2 of Project 2007-17" under the section titled Brief Description of Proposed Standard Modifications/Actions, which states " The Standard Drafting team shall modify NERC Standard PRC-005-2 to add reclosing relays to the standard. In order to do so, the definition of Protection System shall be revised to include reclosing relays, the Facilities portion of the Applicability of the Standard shall be revised to describe

Organization	Yes or No	Question 3 Comment
		those reclosing relays that are included within the standard, and appropriate minimum maintenance intervals (with maximum allowable intervals) shall be added to the standard. The Standard Drafting team shall also make any other changes that are necessary to explicitly address reclosing relays, but shall not make general revisions to the standard, either in content or arrangement." Colorado Springs Utilities position is reclosing relays are used as part of the system restoration process, and should not be associated with the protection or reliability of the system. Reclosing relays should be grouped with SCADA controls of breakers and manual controls of breakers, and should be tested with the same frequency. Breaker reclosing is not used on many lines, and is disabled on many lines. Automatic Breaker Reclosing is a system enhancement, not a system requirement.
Response: Thank you for your comments. The SDT notes that the draft SAR for Phase 2 of Project 2007-17 is not applicable to the current successive ballot and was posted for informational purposes only. In Order 758, FERC directed NERC to include reclosing relays in a future version of PRC-005; the SDT developed this draft SAR to address FERC's directive.		
Duke Energy		Duke Energy votes "Negative" because we strongly object to the wording in the Applicability section 4.2.1. We believe that the wording change to PRC-005-2 draft 4 after the previous Successive Ballot but prior to the associated Recirculation Ballot expanded the reach of the standard to relaying schemes that detect faults on the BES but which are not intended to provide protection for the BES. The SDT's response to our comment directs us to Section 2.3 of the Supplementary Reference And FAQ Document which states "There should be no ambiguity: if the element is a BES element then the Protection System protecting that element should be included within this Standard." We agree with that statement, but point out that Section 4.2.1 is inconsistent with that statement, and has a much broader reach because it includes devices that detect Faults on the BES but which do NOT provide protection for the BES. Compliance audits will be driven by the words in the standard, not the explanations in the Supplementary Reference And FAQ Document. We would appreciate a response to our concern that explains the reliability benefit associated

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		with this expansion of scope, and which specifically addresses the following Duke Energy situation: Duke Energy's standard protection scheme for dispersed generation at retail stations would become subject to the standard due to the changes in section 4.2.1. These protection schemes are designed to detect faults on the BES, but do not operate BES elements nor do they interrupt network current flow from the BES. In the most recent draft, the relays, current transformers, potential transformers, trip paths, auxiliary relays, batteries, and communication equipment associated with the dispersed generation protection scheme would be subject to the requirements in PRC-005-2. Previous drafts of the standard would not have required Duke Energy to maintain the protection system components associated with dispersed generation schemes at retail stations in accordance to the requirements in PRC-005-2. The new wording in section 4.2.1 would add significant O&M costs and resource constraints due to the inclusion of protection system devices at retail stations without increasing the reliability of the BES. Duke Energy does not believe it was the intent of the standard to include elements that did not have an impact on the reliability of the BES. Duke Energy would prefer the following wording for Section 4.2.1: Protection Systems that are installed for the purpose of protecting BES Elements (lines, buses, transformers, etc.)".FERC's September 26, 2011 Order in Docket No. RD11-5 approved NERC's interpretation of PRC-005-1 R1 and R2, stating: "The interpretation clarifies that the Requirements are "applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the [BES] and trips an interrupting device that interrupts current supplied directly from the BES." This interpretation is consistent with the Commission's understanding that a "transmission Protection System" is installed for the purpose of detecting and isolating faults affecting the reliability of the bulk electric system through the use of current interrupting devices."
Response: Thank you for your comments. The SDT believes the Applicability as stated in PRC-005-2 is correct and supports the reliability of the BES. All Protection Systems installed for the purpose of detecting faults on the BES need to be maintained per the requirements of PRC-005-2. The SDT observes that the approved Interpretation addresses the term, "transmission Protection System", and notes that this term is not used within		

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PRC-005-2; thus the Interpretation does not apply to PRC-005-2. Please see Section 2.3 of the Supplementary Reference and FAQ document for additional discussion.		
Entergy Services		Entergy provides the following comments to achieve consistency in the written standards: • Numbers indicating measurable quantities should be numbers: 95%, 5%, etc. and not spelled out. • Words indicating a specific document or entity should be capitalized: this Standard • Words indicating generic devices should not be capitalized: components, faults, monitors, misoperation • 4. If two words go together with a singular meaning they should both be either capitalized or not: Communication Systems
Response: Thank you for your comments. The SDT followed NERC's style guide for the various issues you point out.		
FirstEnergy		FirstEnergy supports the standard and thanks the drafting team for all their hard work.
Response: Thank you for your comments.		
Luminant		In addition to the revised Supplemental Reference and FAQ guide revision requested in question 2, Luminant recommends that Table 1-5; Line 1 and 4 be revised to specifically state that only BES elements (circuit breakers/interrupting devices) are to be tested. There is no benefit to the BES system for testing the non-BES breakers and some locations, trip testing of the breakers would cause a unit black-out due to unit design. Some units do not have start-up transformers. By performing these tests, there is a risk of causing unit damage while the unit is off-line. Therefore Luminant recommends that Table 1-5 be revised to only require BES breakers be tested for compliance purposes. This would be consistent with the requirements covered in Table 3 for UFLS Systems.
Response: Thank you for your comments.		

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The SDT revised Section 15.3.1 of the Supplementary Reference and FAQ document to address this concern, and does not believe that further revision of the standard is necessary.		
Public Utility District No. 1 of Okanogan County		In tables 1-4 with regards to station batteries. 1. DC Supply voltage. Is this reading taken off the batteries or out of the charger? Which read needs to be documented? 2. Unintentional grounds. If the charger has the ability to detect and alarm on unintentional grounds, do we need to manually check this as well? 3. In the 18 month section there is a reference to Float voltage of charger. How do we document in our procedure? Can we use SCADA? 4. In the NICAD battery section. Why can't we do impedance testing? Why only load testing? 5. In table 1-5 there is mention of "Lockout Devices" does this mean that 86 relays are being brought into scope? 6. In table 2 there is discussion with regard to Alarm paths and alarm path monitoring. Table 1-5 item 4 discusses Auxiliary Relays in the control circuit path. Typically, Auxiliary relays in this scenario are closed contacts and open when in an alarmed state. For example, a low SF6 alarm contacts on a breaker interrupts the trip circuit and prevents the breaker from operating. Does this type of auxiliary relay need to be tested every 12 years? 7. For monitoring transmission PTs- Can we measure low side voltage (13kv) PTs multiplied by the power transformer ratio to verify transmission PT accuracy? 8. Table 1-3 describes independent "measurements continuously verified by comparison" Does separate AC measurement need to be connected to same relay? or can it be connected to separate relay with comparison done in SCADA?
Response: Thank you for your comments. 1. The verification of dc voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not		

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malfunctioning, and the standard is indifferent as to where the voltage is actually measured. However, Section 15.4.1 of the Supplementary Reference and FAQ document suggests that this voltage be optimally measured at the battery's main terminals. 2. Per Table 1-4(f) and Table 2, if your charger has the ability to detect and alarm on unintentional grounds and meets the Table 2 requirements, no periodic inspection of unintentional dc grounds is required. 3. As explained in Section 15.4.1 of the Supplementary Reference and FAQ document, the maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltage on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits. Per Table 1-4(f) and Table 2, if your charger has the ability to monitor and alarm to ensure correct float voltage is being applied on the station dc supply and meets the Table 2 requirements, no periodic verification of float voltage of battery charger is required. The standard is proscribed from describing "how". It is left to the entity to determine what methods best address their program. 4. At this time - with the exception of the results of a capacity test - the drafting team is unaware of any published data for nickel-cadmium battery properties that can be measured and trended against the station battery baseline. 5. As explained in Section 15.3 of the Supplementary Reference and FAQ document, if the lock-out relays (86) are electromechanical type components, then they must be trip tested per Table 1-5. 6. As explained in Section 15.3 of the Supplementary Reference and FAQ document, contacts of the 86 or 94 that pass the trip current on to the circuit interrupting device trip coils will have to be checked as part of the 6 or 12 year requirement. Normally-open contacts that are not used to pass a trip signal and normally-closed contacts do not have to be verified. 7. There are multiple methods to verify the current and voltage signal values as explained in Section 15.2 of the Supplementary Reference and FAQ document. 8. It is left to the entity to determine what methods best address their program. Section 15.2 of the Supplementary Reference and FAQ document discusses various methods of conducting this comparison.		
Manitoba Hydro		Manitoba Hydro is maintaining our negative vote based on our previously submitted comments (see comments submitted in the comment period ending on March 28th, 2012).
Response: Thank you for your comment. The SDT has also not changed its position from that expressed in response to the earlier comments.		
Oncor Electric Delivery		On Page 89 of the Supplementary reference and FAQ Draft document on the References page (reference #12) the correct number of the standard should read "Std

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		450-2010" instead of "Std 45-2010."
Response: Thank you for comment. The Supplementary Reference and FAQ document has been corrected.		
Dominion		On the Redline version of the standard, page 11 Version History; Version 2 Action, should PRC-005-1a be listed as PRC-005-1b and PRC-017 listed as PRC-017-0. Additionally, it does not appear that the Version History has captured a complete record of all revisions to this standard.
Response: Thank you for your comments. The references to the approved standards and the Version History have been corrected.		
Brazos Electric Power Cooperative		Please see the formal comments submitted by ACES Power Marketing.
Response: Thank you for your comment. Please see our responses to the comments submitted by ACES Power Marketing.		
PPL Generation, LLC on behalf of its Supply NERC Registered Entities		PPL Generation, LLC thanks the SDT for their effort on this latest version of the standard and has voted affirmatively. We offer the following comments/suggestions: 1.) PPL Generation, LLC would like more direction on how the Tables 1-3 are to be interpreted. Under the left column "Component Attributes," it is not completely clear as to which situation is applicable in order to know what "Maintenance Activity" applies. Either the table's "Component attributes" or the statement "Include the applicable monitored Component attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components" could be more prescriptive on the specific component attributes to provide entities direction as to when exactly each table is to be followed. 2.) In regards to Unresolved Maintenance Issues, PPL Generation, LLC is concerned with the use of the word "efforts" in regards to the use in "shall demonstrate efforts" in Requirement 5. We suggest that either a formal definition of "effort" is provided or more clarity is added in the Requirement 5, shown below, that gives a quantitative

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		scale of what constitutes an effort. "Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues." In its current form, "efforts" can be broadly interpreted by auditors as any number of different required actions of an entity and could potentially lead to inconsistencies in applying the term throughout the regions.
Response: Thank you for your comments. 1. The left column of the Tables describes the monitoring attributes (if any) that are available on the particular components. The center and right columns describe the related maximum maintenance intervals and minimum maintenance activities. **2.** The SDT believes there is sufficient understanding in the industry for the term "efforts" and the risk of compliance jeopardy is minimal.		
Progress Energy		1. R3 and the VSL for R3 seem to imply that an entity would not be in violation of this standard if they exceed their PSMP intervals (including any program grace) as long as the maintenance is performed within the maximum intervals prescribed within the tables. This interpretation was further supported in the previous draft of the Supplemental Reference (Section 8.2.1, page 35), which stated: "According to R3, a strictly time-based maintenance program would only be in violation if the maximum time interval of the Tables is exceeded." However, this statement has been removed from the supplemental document under the latest draft revision. Would the entity be noncompliant if they exceed their PSMP interval but not the maximum table interval? 2. Table 1-4(e): Typo. "Any Protection System dc supply used only for tripping only...." 3. Page 51, 4th paragraph, 5th line: Typo "thre" should be "three."
Response: Thank you for your comments. 1. The standard is defining maximum allowable intervals and minimum acceptable activities for a PSMP. Requirement R3 was revised recently to establish that entities must maintain their Protection System components, at a minimum, in accordance with the relevant tables. Entities are empowered to develop PSMPs that exceed these requirements if they determine such a PSMP is necessary; however, according to Requirement R3, the entity will not be held to their more-aggressive (than the tables) PSMP for compliance monitoring purposes.		

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2. The SDT made the suggested editorial change to Table 1-4(e). **3.** The Supplementary Reference and FAQ document has been corrected as suggested.		
ReliabilityFirst		ReliabilityFirst offers the following comments for considerations: 1. General Comment a. ReliabilityFirst believes not only should there be testing required for individual components (as required Protection System Maintenance Program), ReliabilityFirst believes that the entire Protection System (consisting of all Protective relays, communications systems, Voltage and current sensing devices, etc.) should be tested as a whole. Individually each component may test successfully but while tested as a complete Protection System (through interaction between all the interdependent components), deficiencies in settings along with logic and wiring errors could be discovered. 2. Requirement R5 a. ReliabilityFirst believes the language in Requirement R5 ("...shall demonstrate efforts to correct...") is subjective and non-measurable. It will be difficult in determining what amount of "demonstration" an entity will need to provide in order to be compliant along with lack of timeframe in which the correction needs to be completed. While RFC understands it is hard to prescribe a specific timeframe/deadline (it can depend on various number of supply, process and management problems), RFC believes at a minimum, the applicable entity should be required to develop a Corrective Action Plan to address the Unresolved Maintenance Issue. ReliabilityFirst offers the following modification for consideration: "Each Transmission Owner, Generator Owner, and Distribution Provider shall put in place a corrective action plan to remedy all identified Unresolved Maintenance Issues."
Response: Thank you for your comments. 1. The SDT does not believe it feasible to craft requirements for testing an entire Protection System as a whole that would simultaneously prove performance of every component and believes such invasive testing would jeopardize BES reliability. 2. The SDT's intent is to furnish a way for an entity to address Unresolved Maintenance Issues without the formality and burden of a		

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full-fledged Corrective Action Plan.		
Seattle City Light Operations		SCL supports the position of WECC PNGC with regard to the position paper VRF/VSL recommendation. Specifically, it is the contention of PMGC and members that small entities with maybe 2 or 3 components within a Component Type that sustain a violation will unnecessarily be subjected to a “severe” or “high” VSL assignment due to the % based parameter. We feel the SDT did not adequately address our concerns during the last ballot/comment period. While this is a non-issue for larger entities with hundreds or thousands of individual components, we believe this exposes smaller entities to unnecessary compliance risk. 1. The PNGC Comment Group takes issue with the associated VSLs for R3. For a small entity using a time based maintenance program, even one missed interval could be enough to elevate them to a high VSL despite the limited impact on the Bulk Electric System. Consider an entity with 9 total components within a specific Protection System Component Type. One violation would mean an 11% violation rate, enough to catapult them into a High VSL. Given NERC Guidance (following), this seems to be a contradiction given the language of “...more than one” [NERC Guidance on VSL assignment: i. LOWER: Missing a minor element (or a small percentage) of the required performance. ii. MODERATE: Missing at least one significant element (or a moderate percentage) of the required performance. iii. HIGH: Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. iv. SEVERE: Missing most or all of the significant elements (or a significant percentage) of the required performance.] Thus we support the WECC PNGC suggestion to change the language for “Lower VSL” for R3 to: 'For Responsible Entities with more than a total of 20 Components within a specific Protection System Component Type in Requirement R3, 5% or fewer have not been maintained...' OR 'For Responsible Entities with a total of 20 or fewer Components within a specific Protection System Component Type, 2 or fewer Components in Requirement R3 have not been maintained...'

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Response: Thank you for your comments. The SDT respectfully disagrees and believes that the Standard appropriately incorporates and accounts for the system risks and burdens of maintenance for both large and small entities. The VSLs were developed in accordance with the "FERC VSL Order" and the NERC criteria; for stepped VSLs - Lower VSL is "5% or less", Medium VSL is "more than 5% up to (and including) 10%", High VSL is "more than 10% up to (and including) 15%", and Severe VSL is "more than 15%".		
Public Service Company of New Mexico		Table 1-1 Component Type - Protective Relay and Table 1-2 Component Type - Communications Systems refer to Table 2 Alarm Paths and Monitoring for monitoring related attributes. However, the maximum maintenance interval in rows referring to Table 2 in both Tables 1-1 and 1-2 is 12 calendar years whereas there is a row in Table 2 that if there is an Alarm Path with monitoring (row 2 of Table 2), no periodic maintenance is required. Does this mean that even if there is an Alarm Path with monitoring for which no periodic maintenance is required, the component type - Protective Relay or Communications Systems will still be required to be maintained within the maximum 12 calendar years interval? This appears to be contradictory especially since rows in Tables 1-3, 1-4(f), and 1-5 that refer to Table 2 have "no periodic maintenance specified" under maximum maintenance interval. This also appears to be contradictory to the text provided under bullet 1 of Section 5.2 Extending Time-Based Maintenance which states that - If continuous indication of the functional condition of the Component is available (from relays or chargers or any self-monitoring device), then the intervals may be extended, or manual testing may be eliminated." Rows referring to Table 2 in Tables 1-1 and 1-2 do not suggest that manual testing will be eliminated as it is requiring a 12 calendar year maintenance time interval even if it meets the requirements under table 2 for alarm path with monitoring. PNM recommends adding the following under Maximum Maintenance Interval to be consistent with other tables 1-3, 1-4(f), and 1-5 - "12 calendar years OR no periodic maintenance specified".
Response: Thank you for your comments. For protective relays and communications systems, the only maintenance activity in the last line of the related table is to verify those unmonitored inputs and outputs that are essential to the proper functioning of the Protection System. The SDT sees no appreciable		

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improvement in the standard with your proposed change and respectfully declines to modify the standard.		
Bonneville Power Administration		1. Table 1-2: Communication Systems: BPA believes that the entire section of Table 1-2 needs clarity. A channel, channel performance criteria, & communication system all have very precise definitions in the communications world. (Please refer to Supplemental Frequency AQ - Figure 1 - Typical Transmission System Diagram, Telecommunications Network Cloud)When referring to the terms in Table 1-2, if the drafting team is referring to the 'telecommunications cloud', this section is unclear. BPA believes it is clearer if the drafting team is referring to the two telecommunications equipment panels and requests documented clarification. The traditional term for this would be teleprotection channel or teleprotection function. BPA assumes the intention was teleprotection channel. BPA recognizes that the teleprotection equipment panels, in many modern cases, are built into the relay. For background information, the Telecommunications Network is composed of multiple Communication Systems (40 to 50 is not uncommon) that contain multiple thousand (5-6K) pieces of equipment. These systems and equipment are tied together with hundreds of thousands of Communication Channels and Tributaries. Most of the Channels and Tributaires have, at least a primary and backup (WECC Guideline: Design of Critical Communications Circuits), and some have multiple primary's and backups. All of these are needed to create the circuit connections, as indicated on the diagram from one teleprotection panel to another teleprotection panel. Given the above scenario - the confusion is possible. As an example, for the component attribute: 'Any unmonitored communication system necessary for the correct operation of the protective functions, and not having all the monitoring attributes of a category below.' The 4 calendar month maintenance activity is to: 'Verify that the communications system is functional.' The questions that arise are which systems, the drop system or the transport system? The whole system or just the part carrying the protective signals? What about the channels interconnecting the various systems and so on? BPA suggests clarifying: Any unmonitored teleprotection function necessary for the correct operation of the protective

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		functions, and not having all the monitoring attributes of a category below. The 4 calendar month maintenance activity is to: 'Verify that the teleprotection function is functional' BPA believes this is a much better approach as it identifies only that the teleprotection panels must get inputs and outputs to the relays between them. BPA believes more clarity is still needed. A simple example of an old tone based FSK transfer Trip System over a single point to point analog MW radio channel; the teleprotection panel will normally transmit a guard tone in a particular spectrum over a single radio channel to the teleprotection panel at the far end. BPA understands that one way to verify that the teleprotection function is serviceable in a 4 month maintenance activity is if the guard signal arrives at the opposing end, correct? BPA infers that this is efficient as entities can now monitor loss of guard and have a continuously monitored system which will result in performing just a12 year maintenance. Is this correct? This raises the question of the trip function. Until the trip function is energized from the relay, the circuitry sending the trip by initiating a FSK in not functioning. Does this function needs to be check in addition to the guard function? This raises the question of the MW radio channel. BPA recognizes that the FSK trip signal travels over different spectrum in the analog MW radio. Even if the radio will transmit a Guard FSK signal to the far end, it will not necessarily transmit a Trip FSK signal to the far end (a common hidden failure mode in many MW systems). Do entities need to check for guard at the far end and test that a FSK Trip signal propagates through the radio system and is received at the teleprotection panel? BPA requests clarification in the followings scenario: Using testing inputs as opposed to operating inputs that trips and guards may be initiated from a different set of inputs of the teleprotection panel, and monitored from a different set of outputs on the teleprotection panel (very common on teleprotection equipment). The test might work, but an actual Trip signal would not work (a common hidden failure mode on current available equipment). If one were to say 'good enough' for a 4 month test (and hope any auditors agree if there is ever a false operation). How about the 12 calendar year test? For a point to point analog MW radio,

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		there is only a single channel that can be tested for passage of guard and trip tones. If the radio is redundant, which it most likely is (WECC Guideline: Design of Critical Communications Circuits) then this has to be done twice, once for each path. Can the drafting team clarify this scenario? In a more typical real-world case, the circuit connection, between the two teleprotection panels, will transverse multiple redundant communications systems. If it crosses 4 redundant systems in the communications cloud, then there are a total of 4^2 or 16 possible communication channels, each with different test criteria, that need to be tested. Additionally, the channels are rerouted manually and automatically much faster than a 12 year cycle (daily is not uncommon). Do all these combinations need to be tested? This discussion illustrates the confusion of the current wording. BPA recommends that: If the intention is to test in the 'cloud' or the performance of the 'cloud', BPA believes there needs to be a new standard, or set of standards created to deal with the intricacies of the telecommunication cloud. If the intention was to test the teleprotection channel, BPA believes additional clarity needs to be provided to address the dynamic redundancies and rerouting of the communications system. If the intention was to test the teleprotection function BPA believes additional clarity needs to be provided to test/monitor the functions (inputs and outputs) between the teleprotection panels. 2. Table 1-4(a):VLA Battery: 4 Months/Inspect/Electrolyte Level BPA believes that for a properly designed and installed steady state float charge/long duration discharge type battery plant this is not needed. The inspection at 4 Month intervals will unearth catastrophic failures (Split cells, severe overcharging, etc...). These types of failures can happen anytime, and need to be designed around. Unless the battery plant is under high cyclic load, water usage can be handled in a 12/18 month maintenance cycle. Severe overcharging needs to be dealt with by design/maintenance practices (for example: an Appropriate high voltage alarmed with an immediate call out) since 4 months is too long to wait to detect the condition. Minor overcharging will not be detectable in a 4 month interval (and one wants to very slightly overcharge a battery verse any individual cell being

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		undercharged, but that is a whole different technical discussion). IEEE484 specifies ventilation should be provided for the worst-case hydrogen generation due to overcharging. Other than an inherent manufactures defect that can happen anytime 24/7, splitting cells due to sulfation build up is a slow know process that can be handled in a 12/18 month maintenance cycle with a good visual inspection. Although this is in line with IEEE450, given the specific type of battery configuration in the utility world, this is excessive. Should there be a unique battery plant design, then it is incumbent on that utility to have appropriate shorter intervals. BPA is in support of “For unintentional grounds” and recognizes that it does not apply to intentionally grounded battery systems (teleprotection systems run off of communication batteries in sites where there is no station battery {i.e.: Grand Coulee/Lower Snake}).In general there are two types of batteries used by utilities, outside of their control centers, which will be supplying protective systems. The vast majority is the station battery, which is described very well in the IEEE standards: Switchgear control battery applications typically require output current levels that vary over a relatively long period of time. The battery operates on a float charge during steady state conditions. The battery charger powers relays, indicating lights, and peripheral devices during normal conditions. Instantaneous operation of the circuit breaker and switches require battery output current. Initially, this current may be relatively high for a short duration and then reduce for an extended period of time, followed by another high operating current demand. If the charger output is lost, these low-level currents are supplied by the battery for a specified period. The second is a telecommunications battery supplying the teleprotection equipment (excluding the telecommunications batteries supplying only the communication cloud), which are described very well in the IEEE standards: Telecommunication systems are typically of high reliability, with a minimum uptime of 99.99% is often required. Although the batteries are sized for long duration discharge, short duration discharges are usually the case. Excess charging capacity is often available because of redundant charger configurations and engineered

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		overcapacity. The reserve battery time is usually of long duration.
Response: Thank you for your comments. 1. The SDT does not necessarily agree that the term “teleprotection” is universally used or interpreted consistently in the utility protection industry and believes its use in the standard would not improve the standard. Your comments in the complexity and intricacy of the telecommunications “cloud” are well-taken; however, it was the SDT’s intent to require an overall functional test of the “cloud”-based path, but not an exhaustive test of each and every individual channel that could be involved. Yes, there is some risk in a FSK-based guard/trip scheme that the trip function may not perform even if the guard function does, but the SDT sees this risk as manageable and in line with other risks inherent in interval-based maintenance. **2.** This standard is applicable to station batteries. Please see Section 15.4.1 of the Supplementary Reference and FAQ document for more discussion. The scope of this standard does not include communication site batteries. The SDT believes that PRC-005-2 strikes an appropriate balance between maintenance burden, failure modes, manufacturer recommendations and IEEE battery guidelines.		
Independent Electricity System Operator		The IESO continues to disagree with the VRF assigned to the new Requirements R3 and R4. R3 and R4 ask for implementing the maintenance plan (and initiate corrective measures) whose development and content requirements (R1 and R2) themselves have a Medium VRF. Failure to develop a maintenance program with the attributes specified in R1, and stipulation of the maintenance intervals or performance criteria as required in R2, will render R3/R4 not executable. Hence, we reiterate our request to change R3’s VRF to Medium.
Response: Thank you for your comments. The SDT respectfully disagrees and contends that the consequences of failing to maintain Protection Systems in the required time frames merit a High VRF.		
PNGC Small Entity Comment Group		The PNGC Small Entity Comment Group appreciates the hard work of the Standards Development Team on this difficult and complex project. However we are disappointed with the response to our concerns over the VSL matrix and although we believe on balance this should not be the sole reason for voting "no", we find it difficult to re-cast a "yes" vote and will therefore vote "abstain" to maintain the integrity of the quorum and reflect our position. Your response to our comment;"1.

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		A smaller entity will have less to maintain in accordance with the standard; and, thus, the percentages are still appropriate." reflects a position that indicates are cursory and dismissive review of our concern. We would counter that because a smaller entity has less to maintain, a solely percentage violation measure is therefore inappropriate. We've appended our original comment below in addition to the SDT response. PNGC Comment:1. The PNGC Comment Group takes issue with the associated VSLs for R3. For a small entity using a time based maintenance program, even one missed interval could be enough to elevate them to a high VSL despite the limited impact on the Bulk Electric System. Consider an entity with 9 total components within a specific Protection System Component Type. One violation would mean an 11% violation rate, enough to catapult them into a High VSL. Given the "NERC Guidance (Below), this seems to be a contradiction given the language of "...more than one". a. NERC Guidance on VSL assignment: i. LOWER: Missing a minor element (or a small percentage) of the required performance ii. Moderate: Missing at least one significant element (or a moderate percentage) of the required performance. iii. High: Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. iv. Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance. We suggest changing the language for "Lower VSL" for R3 to: For Responsible Entities with more than a total of 20 Components within a specific Protection System Component Type in Requirement R3, 5% or fewer have not been maintained... Or for Responsible Entities with a total of 20 or fewer Components within a specific Protection System Component Type, 2 or fewer Components in Requirement R3 have not been maintained... SDT response: 1. A smaller entity will have less to maintain in accordance with the standard; and, thus, the percentages are still appropriate.

Response: Thank you for your comments.

The SDT respectfully disagrees and believes that the Standard appropriately incorporates and accounts for the system risks and burdens of maintenance for both large and small entities. The VSLs were developed in accordance with the "FERC VSL Order" and the NERC criteria; for stepped VSLs - Lower VSL is "5% or less", Medium VSL is "more than 5% up to (and including) 10%", High VSL is

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“more than 10% up to (and including) 15%”, and Severe VSL is “more than 15%”.		
US Bureau of Reclamation		The reliability level for protection systems has been lowered by eliminating the requirement for entity defined maintenance and testing procedures. Currently the draft only prescribes that the elements are identified as to when they will be maintained. The FAQ suggested that the PRC-005 did not have sufficient specificity with regard to the PSMP requirement. The entity no longer must be able to document that they were maintained in accordance with any prescribed method, jus that they were maintained in accordance within an acceptable interval. Second, the measure for R1 does not specific what evidence is considered acceptable. This makes the standard hard to enforce.
Response: Thank you for your comments. The standard is defining maximum allowable intervals and minimum acceptable activities for a PSMP. Entities are empowered to develop PSMPs that exceed these requirements if they determine such a PSMP to be necessary. Measure M1 offers examples of documentation that should ease compliance and enforcement.		
Seminole Electric Cooperative, Inc		1. The SDT has provided ONE Protection System Component with two differing maintenance periods, the lockout (86) device. Six years is used for the lockout operation and twelve years is used for contact testing of the lockouts. Earlier the SDT had a similar arrangement with microprocessor relays, the microprocessor relay would be tested on a twelve year cycle but the microprocessor's electro-mechanical trip outputs were to be tested on a six year cycle. The SDT then made a decision that the single microprocessor asset would have a common testing cycle of twelve years, reasonably considering it a single asset with a single maintenance cycle of 12 years. To eliminate confusion with lockout relays, it is recommended that a similar decision be made by the SDT to make a single lockout relay asset have a common maintenance cycle of twelve years. The lockout relay twelve year cycle would include both the lockout operational test and the lockout relay tripping contact tests. This twelve year cycle would also be in direct maintenance alignment with other microprocessor relays and auxiliary relay testing cycles.

Organization	Yes or No	Question 3 Comment
		2. In addition, the sudden pressure relays and their integral control circuit should either be included or excluded. This is a compliance trap and will lead to many findings of non-compliance, based on sudden pressure relays not being included in many prior versions and currently not included in this version, except for their DC control circuit.
Response: Thank you for your comments. 1. The SDT believes that electromechanical lockout relays need periodic operation. As such, these devices are required to be exercised at the same 6 year interval required for electromechanical relays. The SDT recognizes the risk of human error trips when working with testing of lockout devices but believes these risks can be managed. Performance based maintenance is an option if you want to extend the intervals beyond 6 years. However, the SDT modified Table 1-5 to remove other auxiliary relays, etc, from this activity, and clarified that the verification of such devices is included within the 12-year unmonitored control circuitry verification. **2.** The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-2 testing requirements because the SDT is unaware of industry recognized testing protocol for the sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently approved PRC-005-1 and with the SAR for Project 2007-17.		
Florida Municipal Power Agency		1. The SDT is still not agreeing with the applicability as interpreted and approved by FERC PRC-005-1b Appendix 1 that basically says that applicable Protection Systems are those that protect a BES Element AND trip a BES Element. The interpretation states: In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES. The SDT continues to ignore this FERC approved interpretation, and this omission causes us to vote Negative again. The basic issue is that some distribution protection will be swept in with the applicability of the standard, which states: 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines,

Organization	Yes or No	Question 3 Comment
		buses, transformers, etc.) 2. Many (most) network distribution systems that have more than one source into a distribution network will have reverse power relays to detect faults on the BES and trip the step-down transformer to prevent feedback from the distribution to the fault on the BES. This is not a BES reliability issue, but more of a safety issue and distribution voltage issue. These relays would be subject to the standard as the applicability is currently written, but, should not be and they are currently not within the scope of PRC-005-1b Appendix 1 because the step-down transformer (non-BES) is tripped and not a BES Element (hence, the "and" condition of the interpretation is not met). There are many other related examples of distribution that might be networked or have distributed generation on a distribution circuit where such reverse power relays, or overcurrent relays with low pick-ups, are used for safety and distribution voltage control reasons and are not there for BES Reliability. To make matters worse, for these Reverse Power relays, it is pretty much impossible to meet PRC-023 because the intent of the relay is to make current flow unidirectional (e.g., only towards the distribution system) without regard for the rating of the elements feeding the distribution network. So, if these relays are swept in, and if they are on elements > 200 kV, then the entity would not be able to meet PRC-023 as that standard is currently written. So, the SDT should have adopted the FERC approved interpretation. We have made this recommendation several times before.

Response: Thank you for your comments.

1. The SDT believes the Applicability as stated in PRC-005-2 is correct and supports the reliability of the BES. The SDT observes that the approved interpretation addresses the term, "transmission Protection System", and notes that this term is not used within PRC-005-2; thus the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses "Protection Systems that are installed for the purpose of detecting faults on BES Elements." Please see Section 2.3 of the Supplementary Reference and FAQ document for additional discussion.
2. In the case you cite, the transformer is likely not a BES element; thus reverse power relays, even if installed to detect a fault in the transformer rather than actually to detect transformer energizing current, would not be included (as they are not installed for the purpose of detecting a fault on the BES). Please note that reverse power relays respond to real power (watts) instead of

Organization	Yes or No	Question 3 Comment
reactive power, and fault current is highly reactive.		
Tennessee Valley Authority		This comment is regarding the Implementation Plan for Requirements R3 and R4, 1. (Page 3 of 5) of The Implementation Plan for Project 2007-17 Protection Systems Maintenance and Testing PRC-005-02. Number 1. states: For Protection System component maintenance activities with maximum allowable intervals of less than one (1) calendar year, as established in Tables 1-1 through 1-5: o The entity shall be 100% compliant with PRC-005-2 on the first day of the first calendar quarter eighteen (18) months following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter thirty (30) months following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. TVA Comment: Even though TVA has already started a plan to address this issue, it will take several years to implement automatic checkback on 541 carrier blocking sets on the TVA system. TVA performed quarterly testing from 2000 through 2007, then after data showed failures not attributed to signal margin, the test was changed to twice a year in 2008. TVA carrier failure rate has not increased since the frequency was changed in January 2008 from 4 tests/year to 2 tests/year. We suggest a graduated implementation plan for this effort similar to number 3 (being compliant 30% in 24 months, 60% in 36 months, and 100% in 48 months) on Pages 3 and 4 of 5.
Response: Thank you for your comments. If an entity's experience is that these components require less-frequent maintenance, a performance-based program in accordance with Requirement R2 and Attachment A is an option. Your comments on your failure rates seems to indicate that you are performing a failure rate analysis similar to what is required under Attachment A for performance maintenance. While it is unfortunate that you feel you cannot meet the implementation requirements, the SDT believes that the existing plan is judicious in its time frame relative to the maximum intervals required by the standard.		
Tacoma Power		1. This is a follow-up question/comment from the previous round of balloting; please see the part in all capitals. It is still unclear whether Section 15.3 permits periodically verifying DC voltage at the actuating device trip terminals as an

Organization	Yes or No	Question 3 Comment
		acceptable method of accomplishing the maintenance activity identified in Table 1-5 for unmonitored control circuitry associated with protective functions IF DC VOLTAGE IS VERIFIED AT EACH APPLICABLE SET OF ACTUATING DEVICE TRIP TERMINALS SO THAT EVERY TRIP PATH IS ADDRESSED. It is recommended that this approach be considered acceptable, provided that auxiliary relays are operated within the maximum maintenance interval. 2. In Table 1-2, does the 'channel' include the communication interface/driver that is part of the end device?
Response: Thank you for your comments. 1. The method chosen for verification is left to the entity. The second to last paragraph of Section 15.3 of the Supplementary Reference and FAQ document states: "Monitoring of the control circuit integrity allows for no maintenance activity on the control circuit (excluding the requirement to operate trip coils and electromechanical lockout and/or tripping auxiliary relays). Monitoring of integrity means to monitor for continuity and/or presence of voltage on each trip path. For Ethernet or fiber-optic control Systems, monitoring of integrity means to monitor communication ability between the relay and the circuit breaker." If your suggested activity verifies each and every individual path to the trip coil, it may be an effective method of addressing this requirement; simply checking for voltage at the trip coil may not verify all individual paths. 2. Please see Section 15.5.1 of the Supplementary Reference and FAQ document. The maintenance activities in Table 1-2 related to "channel" have been revised to "communications systems"		
BAE Batteries USA		This revision is a major improvement over the previous draft. Hopefully, the comments above are seen in the light of ensuring basic accuracy of the revised statements. They are not intended to materially change the intent of the position agreed upon at the last drafting team meeting.
Response: Thank you for your comments.		
HHWP		VSL should not be a function of "specific Protection System Component Type". VSL should look at percentage of TOTAL Protection System Components that were not tested within scheduled test date. Consider the entity with 400 Protection System Components, including 2 station battery systems. If that entity completed 399 of 400 tests within schedule and missed 1 battery test, the VSL would be high or severe.

Organization	Yes or No	Question 3 Comment
		Alternatively, if the entity completed 399 of 400 tests, but the missed test was one of 200 protective relays, the VSL would be low. There is no assurance though that the missed battery test resulted in higher risk for the BES than the missed protective relay test. As a result the relationship between VSL and the degree of violation severity lacks predictability.
Response: Thank you for your comments. The SDT disagrees because a battery supplies control power to numerous protective schemes, failure to ensure that the battery is fit for duty is more egregious than missing one component of numerous schemes.		
Consumers Energy		1. We agree with the purpose in section 3 of the Standard. However, section 4.2.1 expands the scope from "affecting the reliability of the Bulk Electric System" to "detecting Faults on BES Elements". In our opinion, the Applicability should be limited to the stated Purpose. Expanding the scope as is done in 4.2.1 greatly increases the number of Protection Systems covered without an increase in reliability of the BES. We prefer the applicability as expressed in Appendix 1 of PRC-005-1b. 2. We suggest changing "Component Type" in R1.2 to something similar to "Segment" as defined within the Standard. A "Component Type" limits to one of five categories, whereas a "Segment" must share similar attributes. 3. In item 2 of the second section of Attachment A, it is only necessary to use 5%, as 5% of a Segment (minimum of 60) is always 3 or more.
Response: Thank you for your comments. 1. The SDT believes the Applicability as stated in PRC-005-2 is correct and supports the reliability of the BES. The SDT observes that the approved interpretation addresses the term, “transmission Protection System”, and notes that this term is not used within PRC-005-2; thus the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses “Protection Systems that are installed for the purpose of detecting faults on BES Elements.” Please see Section 2.3 of the Supplementary Reference and FAQ document for additional discussion. 2. In the documentation to support Requirement R1.2, an entity can list different technologies within a Component Type along with their respective monitoring attributes. The SDT sees no appreciable improvement in the standard with your proposed change and respectfully declines to modify the standard.		

Organization	Yes or No	Question 3 Comment
3. The SDT agrees with your observation but sees no appreciable improvement in the standard with your proposed change and respectfully declines to modify the standard.		
Alliant Energy		We appreciate the work done by the SDT and believe it is an excellent product.
Response: Thank you for your comments.		
Georgia Transmission Corporation		We cast our ballot as an affirmative vote and agree with the nature of the standard. We raise concerns on the measures that are very prescriptive on documentation. We prefer a standard based on the program and measures that track the application and performance of the groups program. Maintaining the documentation for individual elements becomes a group's prime directive along with maintaining the equipment; this develops a process more controlled by documentation than results. This also adds a level of complexity for data retention, the drafting team tried to resolve by reducing the load of data. We contend the retention levels to be extreme considering some of the 12 calendar year cycles, interpret the data for compliance to be 24 years. One cannot remove previous documents until new maintenance performed 12 years after the current recorded date. We recommend reducing the data retention to list or check sheets and not the extreme of each individual component. Another important factor in managing the data is the capability of retrieval after 12 or 24 years. Some systems and formats are not available for 12 or 24 years and add a burden on companies to maintain legacy systems or convert massive amounts of data.
Response: Thank you for your comments. To be assured of compliance, the SDT believes the Compliance Monitor will need the data for the most recent performance of the maintenance, as well as the data for the preceding maintenance period. This seems to be consistent with what auditors are expecting (per the SDT's experience), and is also consistent with Compliance Process Bulletins 2011-001 and 2009-05. This seems to be consistent with what auditors are expecting (per the SDT's experience), and is also consistent with Compliance Process Bulletins 2011-001 and 2009-05. The SDT has specified the data retention in the posted standard to establish this level of documentation. The entity is urged to assure that data is retained as specified within the standard.		
Nebraska Public Power District		1. We recommend removing requirement 5. This is adding the requirement for a

Organization	Yes or No	Question 3 Comment
		corrective action program to the standard. Performance metrics should be utilized to measure if a registered entity is correcting maintenance deficiencies in a timely manner. Examples of performance metrics include: o A Countable event has already been defined in the definition of terms, which would cover the need to replace equipment. o The quantity and causes of Misoperations are a direct correlation to good or poor maintenance practices and corrective actions by a utility. o TADS records events which are initiated by failed protection system equipment and would identify utilities with poor corrective action processes. 2. Can you show us a study or references justifying why records need to be kept for longer than the end of the current audit period. We are concerned that the complexities and costs of tracking and maintaining records, along with the corresponding maintenance program and PRC-005 revision that old tests would fall under will be an undue cost to small utilities. We suggest requiring entities to retain the last maintenance record or any records created during the current audit period. 3. The comment from the previous consideration of comments, "The SDT believes that Protection Systems that trip (or can trip) the BES should be included" seems to include any device that can affect the BES. This sets a precedence to include any device that can trigger trip coils into the maintenance system. These devices are meant to protect equipment and not the BES. 4. Based on the IEEE device numbers, please indicate which devices are part of the BES protection system and should be included in a maintenance program. 5. Why do functional trip checks need to be done on any interval if checks are done upon commissioning, maintenance and modification? We suggest eliminating any interval and making the requirement to check upon commissioning, maintenance and modification. 6. Comments on SAR for 2007-17 Very few reclosing relays protect the BES. Most reclosing relays actually would have a negative impact on the reliability of the bulk electric system. It is imperative that the SDT clearly define what types of reclosing relays are referred to here, and if it pertains to ANY reclosing relay that

Organization	Yes or No	Question 3 Comment
		can affect the BES. 7. There is a difference between components designed to protect the BES and components which can affect the BES. 8. For R5 if the maintenance interval is 6 years does the maintenance issue become an "unresolved" item immediately or does the next maintenance interval 6 years later need to be reached before it takes on an unresolved status to be auditable under R5? 9. Comments: Suggest for monitored microprocessor relays in Table 1-1 and 3 to change wording to verify "settings are as specified that are essential to the proper functioning of the protection system". Many settings are not essential. 10. A key concern is will the reliability of the bulk electric system be affected negatively due to increased risk from human element initiated events as a result of the more frequent functional trip checks that will be required. I suggest there be consideration that the interval for functional tests be moved to the minimum frequency of 12 years to minimize this unknown but present risk.

Response: Thank you for your comments.

1. The SDT disagrees:
   NERC has demonstrated its belief that returning Protection System devices to good working order exists currently as a required element of a sound maintenance program subject to the existing Protection System maintenance and testing standard, PRC-005-1. For reference, NERC Compliance Application Notice CAN-0043 (Posted Final 12/30/2011) directs Compliance Enforcement Authorities (CEAs) to "…look for relay test results or field records with annotations such as "as-found" readings or pass/fail results; <u>if failed, then adjustments made. The maintenance record for adjustments may be requested"</u>.
   Management of completion of the identified unresolved maintenance issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase "demonstrate efforts to correct" (with guidance from NERC Staff) because of the concern that many more complex unresolved maintenance issues might require greater than the remaining maintenance interval to resolve (and yet still be a "closed-end process"). For example, a problem might be identified on a VRLA battery during a 6 month check. In instances such as one that requires battery replacement as part of the long term resolution, it is highly unlikely that the battery could be replaced in time to meet the 6 calendar month requirement for this maintenance activity. The SDT does believe corrective actions should be timely but concludes it would be impossible to postulate all possible

Organization	Yes or No	Question 3 Comment
remediation projects and therefore impossible to specify bounding time frames for resolution of all possible unresolved maintenance issues, or what documentation might be sufficient to provide proof that effective corrective actions are being undertaken. 2. To be assured of compliance, the SDT believes the Compliance Monitor will need the data for the most recent performance of the maintenance, as well as the data for the preceding maintenance period. This seems to be consistent with what auditors are expecting (per the SDT's experience), and is also consistent with Compliance Process Bulletins 2011-001 and 2009-05. This seems to be consistent with what auditors are expecting (per the SDT's experience), and is also consistent with Compliance Process Bulletins 2011-001 and 2009-05. The SDT has specified the data retention in the posted standard to establish this level of documentation. The entity is urged to assure that data is retained as specified within the standard. 3. The response cited from a previous consideration of comments was specifically related to sudden pressure relays. The Applicability 4.2.1 of the standard, specifically states, "…installed for the purpose of detecting Faults on BES Elements". 4. It is left to the entity to determine which devices and their complementary IEEE device numbers are installed for the purpose of detecting Faults on BES Elements. 5. The standard does not specify "functional trip tests", but instead requires that various elements of the dc control circuit be verified at various intervals. Also, FERC Order 693 directs NERC to establish maximum allowable maintenance intervals for Protection System components. Please see Section 15.3 of the Supplementary Reference and FAQ Document. 6. Reclosing relays are not covered in PRC-005-2. In Order 758, FERC directed NERC to include reclosing relays in a future version of PRC-005; the SDT developed the draft SAR to address FERC's directive 7. The SDT agrees; the standard explicitly covers "Protection Systems that are installed for the purpose of detecting Faults on BES elements (lines, buses, transformers, etc.)". 8. The item does not become an "Unresolved Maintenance Issue" unless it is not corrected before the current maintenance interval expires. 9. The SDT sees no appreciable improvement in the standard with your proposed change and respectfully declines to modify the standard. 10. The SDT believes that performing these maintenance activities at the specified intervals will benefit the reliability of the BES. The standard does not specify "functional trip tests", but instead requires that various elements of the dc control circuit be verified at various intervals.		
Western Area Power Administration		Western Area Power Administration is appreciative of the hard work done by the SDT and NERC. 1. We respectfully submit our professional opinion that the increased relay testing

Organization	Yes or No	Question 3 Comment
		required by the PRC-005-2 will result in a net degradation to the reliability of the BES due to human hands disturbing working systems. 2. We propose that auxiliary relays be tested at commissioning and anytime the circuits are rewired or redesigned. If there is evidence that the relay has functioned properly in its current configuration then the best practice for insuring reliability is to leave it alone. 3. The maintenance interval of 6 years for lock-out relay testing is not consistent with 12 year interval of auxiliary relay testing or control circuit testing. No justification is provided for this increased testing interval of lock-out relays versus other electro-mechanical devices. These inconsistent testing intervals, within the same protection control schemes and protective devices, will complicate the industry's Protection System Maintenance Program and cause an increase in maintenance costs. 4. Condition Based Monitoring or Performance Based Monitoring are not allowed on trip coil circuits or lock-out relays. This is inconsistent with current or future technology. Deviation from the 6 year testing interval should be allowed, using CBM or PBM. The Standard should not present a barrier to technology advancements or industry initiatives. The continuous, frequent testing of these devices is detrimental to system reliability. 5. Disagree with testing of the dc control portion of the sudden pressure device as defined by the FAQ. We feel that this device and its wiring were deemed out of scope previously.

Response: Thank you for your comments.

1. The SDT believes that performing these maintenance activities at the specified intervals will benefit the reliability of the BES.
2. The SDT believes that performing these maintenance activities at the specified intervals will benefit the reliability of the BES. Also, FERC Order 693 directs NERC to establish maximum allowable maintenance intervals for Protection System components.
3. The SDT believes that electromechanical lockout relays need periodic operation to remain reliable. As such, these devices are required to be exercised at the same 6 year interval required for electromechanical relays. Performance based maintenance is an option if you want to extend the intervals beyond 6 years.
4. Performance-based maintenance per Attachment A of the standard may be applied to both trip coil circuits and lockout relays.

Organization	Yes or No	Question 3 Comment
5. The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from the definition of Protection System because the SDT is unaware of industry recognized testing protocol for the sensing elements. This position is consistent with the currently-approved PRC-005-1 and the SAR for Project 2007-17.		
Southwest Power Pool NERC Reliability Standards Development Team		N/A
Idaho Power Company		No additional comments.
Kansas City Power & Light		No other comments.

END OF REPORT