Consideration of Comments

Project 2007-17 Protection System Maintenance and Testing

The Protection System Maintenance and Testing Drafting Team would like to thank all commenters who submitted comments on the 4th draft of the standard for Protection System Maintenance. These standards were posted for a 30-day public comment period from July 27, 2012 through August 27, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 36 sets of comments, including comments from approximately 102 different people and from approximately 65 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

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

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration of all Comments Received:

The only edit to the standard was to add an "s" to "communication" in several locations within Table 1-2 for consistency. The term is now "communications system" throughout the table.

Definitions: No changes made.

Applicability: No changes made.

Requirements: No changes made.

Tables: In Table 1-2, added an "s" to "communication" in several locations for consistency. The term is now "communications system" throughout the table.

Measures: No changes made.

VSLs: In the VSLs for Requirement R5, the word "identify" was added to each VSL to be consistent with the requirement.

Supplementary Reference and FAQ Document: Various spelling and punctuation errors were corrected, and additional content was added to improve the reference document.

Implementation Plan: No changes made.

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

Unresolved Minority Views:

- A few commenters questioned the inclusion of breaker trip coil verification, auxiliary relay verification, and/or lockout relay verification. The drafting team responded that each of these devices needs to be maintained at the prescribed intervals to assure reliability.
- Several commenters were concerned that an entity has to be "perfect" in order to be compliant; the SDT responded that NERC Standards currently allow no provision for any degree of non-performance relative to the requirements.
- Several commenters continued to object to inclusion of UFLS and UVLS relays, in that they may not be installed on BES equipment. The drafting team responded that these devices, while not on BES equipment, are installed for the reliability of the BES, and are therefore included. The drafting team further noted that these devices are currently addressed in PRC-008-0 and PRC-011-0.
- A few commenters questioned the inclusion of the dc control circuitry for sudden pressure relays even though the relays themselves are excluded from the definition of "Protection System"; the SDT reiterated its position that this dc control circuitry is included because the dc control circuitry is associated with protective functions.
- Several commenters expressed concerns regarding Requirement R5 and Unresolved Maintenance Issues. The SDT explained its rationale for the requirement as drafted.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1

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

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

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	Robert Rhodes	Southwest Power Pool	SPP	NA
3.	John Allen	City Utilities of Springfield	SPP	1, 4
4.	Clem Cassmeyer	Western Farmers Electric Cooperative	SPP	1, 3, 5
5.	Terri Pyle	Oklahoma Gas and Electric	SPP	1, 3, 5
6.	Sandra Sanscrainte	ITC holdings	SPP	NA
7.	Katie Shea	Westar Energy	SPP	1, 3, 5, 6
8.	Tim Bobb	Westar Energy	SPP	1, 3, 5, 6

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

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
4.	Group	Connie Lowe	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Garton		NPCC	5, 6
2.	Louis Slade		RFC	5, 6
3.	Randi Heise		SERC	5, 6
4.	Mike Crowley		SERC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	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.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
3.	Jim Howard	Lakeland Electric	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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Brenda Hampton	Luminant						X				

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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
2.	Scott Brame	North Carolina Electric Membership Corporation	RFC	1, 3, 4, 5
3.	Clem Cassmeyer	Western Farmers Electric Cooperative	SPP	1, 5
4.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
5.	Ashley Gonyer	East Kentucky Power Cooperative	SERC	1, 3, 5

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rusty Hardison		SERC	1
2.	Pat Caldwell		SERC	1
3.	David Thompson		SERC	5

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.	Jerry Finley		SERC	1
5.	Robert Brown		SERC	5
6.	Tom Vandervort		SERC	5
7.	Annette Dudley		SERC	5

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jason	Burt	WECC	1
2.	Heather	Laslo	WECC	1
3.	Fred	Bryant	WECC	1
4.	Rita	Coppernoll	WECC	1
5.	Mason	Bibles	WECC	1
6.	Brenda	Vasbinder	WECC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Individual	Joe Uchiyama	O&M Group						X			X	
11.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
12.	Individual	Brandy A. Dunn	Western Area Power Administration	X					X				
13.	Individual	Cole Brodine	Nebraska Public Power District	X		X		X					
14.	Individual	Tom Finch	CYPL			X							
15.	Individual	Eric Scott	City of Palo Alto			X							
16.	Individual	Cleyton Tewksbury	Bridgeport Energy					X					
17.	Individual	Joe O'Brien	NIPSCO	X		X		X	X				
18.	Individual	Thad Ness	American Electric Power	X		X		X	X				
19.	Individual	J. S. Stonecipher, PE	Beaches Energy Services	X								X	
20.	Individual	Chris McVicker	Puget Sound Energy	X				X					
21.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
22.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
23.	Individual	Steven Wallace	Seminole Electric Cooperative, Inc.			X	X	X	X				
24.	Individual	Kirit Shah	Ameren	X		X		X	X				
25.	Individual	Scott Bos	Muscatine Power and Water	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
26.	Individual	Michelle R D'Antuono	Ingelside Cogeneration LP										
27.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
28.	Individual	Anthony Jablonski	ReliabitliyFirst										X
29.	Individual	Yves Lavoie	Primax Technologies Inc.										
30.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
31.	Individual	Eric Salsbury	Consumers Energy			X	X	X					
32.	Individual	Jonathan Meyer	Idaho Power Company	X		X							
33.	Individual	Brad Harris	CenterPoint Energy	X									
34.	Individual	Brett Holland	KCP&L/ KCPL-GMO	X		X		X	X				
35.	Individual	Edward Amato	Midtronics Inc										
36.	Individual	Chris Searles	IEEE Stationary Battery Committee Task Force										

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

It is not necessary to answer the remainder of the questions unless you have additional comments that have not already been provided by the entity whose comments you are supporting. Each entity that indicates support for another entity's comments will be counted as having provided comments, regardless of whether they provide any additional comments.

Summary Consideration:

Organization	Agree	Support Comments Submitted by Another Entity
Northeast Power Coordinating Council		
Southwest Power Pool Reliability Standards Development Team		
Duke Energy		
Dominion		
Florida Municipal Power Agency		
Luminant		
ACES Standards Collaborators		
Tennessee Valley Authority		

Organization	Agree	Support Comments Submitted by Another Entity
Bonneville Power Administration		
O&M Group		
Southern Company		
Western Area Power Administration		
Nebraska Public Power District		
CYPL		City of Palo Alto Utilities
City of Palo Alto		
Bridgeport Energy		
NIPSCO		
American Electric Power		
Beaches Energy Services		
Puget Sound Energy		
Manitoba Hydro		
Tacoma Power		
Seminole Electric Cooperative, Inc.		Florida Municipal Power Agency and the Illinois Municipal Power Agency, Duke Energy and WAPA

Organization	Agree	Support Comments Submitted by Another Entity
Ameren		
Muscatine Power and Water		MIdwest Reliability Organization NERC Standards Review Forum (MRO NSRF)
Ingelside Cogeneration LP		
American Transmission Company		
ReliabitliyFirst		
Primax Technologies Inc.		
Illinois Municipal Electric Agency		
Consumers Energy		
Idaho Power Company		
CenterPoint Energy		
KCP&L/ KCPL-GMO		
Midtronics Inc		

1. **In response to stakeholder input, the SDT made several changes to Table 1-2 of the standard, as detailed below:**
    - **The interval for the second portion of the first row of the table was changed from 12 years to 6 years.**
    - **The term "channels" was modified to "communications system" in two locations.**
    - **The Component Attributes in the last row were modified to clarify that all attributes must be present to use the associated intervals and activities.**

Do you agree with these changes? If not, please provide specific suggestions for changes to Table 1-2 in the comment area.

Summary Consideration: In general, the industry was supportive of the changes to the table. More clarification on the scope of the "communications systems" was provided in Section 15.5.1 of the Supplementary Reference and FAQ document, and the term, "communication system" was corrected to "communications system."

Organization	Yes or No	Question 1 Comment
Bonneville Power Administration	No	BPA believes that changing the language from "channels" to "communications systems" does not clarify the intent since "communications systems" is not defined in the standard. The term "communications systems" which is referenced in the Supplementary Reference and FAQ document remains ambiguous. BPA recommends one of these two definitions be included in the standard:1) If the intent is to cover only the Communications Equipment and "channel" as defined above:"Communications System" - The Communications System as defined for the purposes of PRC-005-02 consists of a Component's signaling inputs and outputs and the communications channel that these signals traverse. The intervening carrier communications devices that transport this channel are explicitly excluded from the definition of Communications System.2) If the intent is to cover the Communications Equipment, "channel" and the cloud functionally:"Communications System" - The Communications System as defined for the purposes of PRC-005-02 consists of a Component's

Organization	Yes or No	Question 1 Comment
		signaling inputs and outputs and the communications channel that these signals traverse. The Communications System includes the simple end-to-end functionality of the intervening carrier communications devices that transport this channel but explicitly excludes intermediate switching, redundant paths, packet routing, digital cross-connections and other “cloud” carrier elements from the definition of Communications System.
Response: Thank you for your comments. It is the drafting team’s intent to require the entity to perform maintenance on the protective system communications part of the scheme to verify that it is performing as required. Both the communications equipment and the channel are part of that. If that channel is a third-party leased circuit, then the entity can only verify performance of the channel and not maintain any of its equipment. If the channel is a power line carrier and owned by the entity, the performance can be verified and the equipment can be maintained, if necessary. This standard is proscribed from describing “how” to perform an overall functional test of a communications system; it is left to the entity to determine what methods best address their program. **Also, Section 15.5.1 of the Supplementary Reference and FAQ document was revised to further discuss communications systems.**		
Southern Company	No	Suggestion - Change the interval back to 12 years instead of 6 years. The 12 year interval is reasonable considering that un-monitored communications systems will be functionally tested every 4 months
Response: Thank you for your comments. The drafting team respectfully disagrees. Although an entity functionally tests an unmonitored communications system every four months, there is no requirement to have the pertinent performance criteria verified as part of this functional test. Testing the communications system's performance criteria involves additional tests, such as those described in Section 15.5.1 of the Supplementary Reference and FAQ document. Of course, an entity can always perform both types of tests on a four-month interval, but at this time we see no reason to have the performance criteria verification at a four-month interval. An entity has the latitude to perform maintenance more frequently than specified, if it feels that such maintenance is needed.		
Tacoma Power	Yes	In Table 1-2, for unmonitored communications systems, under Maintenance Activities, ‘communication system’ is used, but in the next row,

Organization	Yes or No	Question 1 Comment
		'communications system' is used. These terms should be consistent.
Response: Thank you for your comment. The drafting team has revised the Table 1-2 to consistently use "communications systems."		
Ameren	Yes	Ameren supports these changes in the interest of BES reliability.
Response: Thank you for your support.		
Ingelside Cogeneration LP	Yes	Ingleside Cogeneration LP was prepared to support a six year maintenance interval - which was specified in all other drafts of PRC-005-2. We agree that the project team's modification is necessary to correct a mistake that crept into the last version.
Response: Thank you for your support.		
Northeast Power Coordinating Council	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
Duke Energy	Yes	
Dominion	Yes	
Chris Searles	Yes	
Florida Municipal Power Agency	Yes	
Luminant	Yes	

Organization	Yes or No	Question 1 Comment
ACES Standards Collaborators	Yes	
Tennessee Valley Authority	Yes	
O&M Group	Yes	
Western Area Power Administration	Yes	
Nebraska Public Power District	Yes	
City of Palo Alto	Yes	
Bridgeport Energy	Yes	
American Electric Power	Yes	
Beaches Energy Services	Yes	
Puget Sound Energy	Yes	
American Transmission Company	Yes	
ReliabitliyFirst	Yes	
Idaho Power Company	Yes	
CenterPoint Energy	Yes	
KCP&L/ KCPL-GMO	Yes	
Midtronics Inc	Yes	

2. **The SDT modified the Implementation Plan as follows:**

- **Within “Retirement of Existing Standards,” the legacy standards will be retired upon full implementation of PRC-005-2, rather than upon PRC-005-2 becoming effective.**
- **Within “General Considerations,” each entity shall be responsible for maintaining each of their Protection System components according to their maintenance program already in place for the legacy standards (PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0) or according to their maintenance program for PRC-005-2, but not both.**

Do you agree with these changes? If not, please provide specific suggestions for changes to the Implementation Plan in the comment area.

Summary Consideration: The commenters largely supported the Implementation Plan, including the changes made at this revision. Several commenters questioned whether the added text within “General Considerations” is necessary, in that it essentially duplicates statements made elsewhere in the Implementation Plan; the drafting team believes that the additional emphasis is useful. No changes were made to the Implementation Plan in response to comments.

Organization	Yes or No	Question 2 Comment
Southern Company	No	The "General Consideration" sentence in question above is superfluous and therefore unnecessary. The instruction provided in the sentence is (repeated and) more clearly stated in the first sentence of the "Retirement of Existing Standards:" section.
Response: Thank you for your comment. The drafting team believes that the modification to the “General Considerations” section of the Implementation Plan adds clarity.		
Western Area Power Administration	No	The logistics of these statements are confusing and need further clarification as to intent and implementation.
Response: Thank you for your comment. The drafting team believes that the implementation plan is clear. The entity should follow the previous maintenance intervals for any specific components until that component is addressed by PRC-005-2. As the		

Organization	Yes or No	Question 2 Comment
transition is occurring, the entity should adjust its maintenance and testing schedule so that they are able to demonstrate that the required percentage of components meet the maintenance intervals given in the PRC-005-2 tables at each of the percent compliant milestones given in this Implementation Plan.		
Tennessee Valley Authority		The intent of this modification is not clear. It could be interpreted as allowing an entity, for any given Protection System component identified in Table 1-1 through Table 1-5, to choose to maintain those components under an existing maintenance program that is compliant with the legacy standards until PRC-005-2 completely retires PRC-005-1b, PRC-008-0, PRC-011-0 and PRC-017-0 (first calendar quarter one hundred fifty-six (156) months following regulatory approval of PRC-005-2). For example, if an entity elects to maintain unmonitored communications system components described in Table 1-2 using its program that is compliant with the legacy standards, when would it have to meet the intervals defined in Table 1-2? The use of "or" under "General Considerations" indicates that compliance with the legacy standards is acceptable until such time that all of the legacy standards are retired.
Response: Thank you for your comment. The drafting team believes that the Implementation Plan is clear. **The entity should follow the previous maintenance intervals for any specific components until that component is addressed by PRC-005-2. As the transition is occurring, the entity should adjust its maintenance and testing schedule so that they are able to demonstrate that the required percentage of components meet the maintenance intervals given in the PRC-005-2 tables at each of the percent compliant milestones given in this Implementation Plan.** **If an entity elects to maintain unmonitored communications system components described in Table 1-2 using its program that is compliant with the legacy standards, it would have to meet the intervals defined in Table 1-2 according to the Implementation Plan for Requirements R3 and R4.**		
ACES Standards Collaborators	Yes	We thank the drafting team for this consideration that will allow early compliance with the new version of the standard. This plan should avoid many of the transitional issues that have occurred with other new versions of standards.
Response: Thank you for your comment.		

Organization	Yes or No	Question 2 Comment
American Electric Power	Yes	We believe the text "Once an entity has designated PRC-005-2 as its maintenance program for specific Protection System components, they cannot revert to the original program for those components" does improve the clarity of the standard.
Response: Thank you for your comment.		
Ameren	Yes	Ameren supports this practical reality.
Response: Thank you for your comment.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP sees the modifications to the implementation plan as a clarification-only. We had anticipated that auditors will look for evidence that a legacy program remains in place until a specifically-identified transition date. In fact, the project team should consider adding an allowance for entities to adopt PRC-005-2 immediately upon FERC's approval. This may mean in rare cases that maintenance activities and intervals managed in accordance with PRC-005-1b will drop out of the program; but if the industry and regulatory bodies agree that the new program is superior, there is no reliability purpose served by waiting. Furthermore, the maintenance activities will continue anyways - they will just not be subject to auditor review. Unfortunately, NERC Compliance has taken the opposite position for the implementation of the CIP version 4 "bright-line criteria" - which we believe is counter-productive to our shared commitment to reliability. Just as with PRC-005-2, a thorough evaluation showed that the elimination of ambiguity reduces risk to the greater system. It is disingenuous to require outdated standards to remain in place simply to avoid a possibility that a borderline facility remain on the regulatory books.
Response: Thank you for your comments. The drafting team suggests that, in the event that an entity fully implements PRC-005-2 for all components (i.e., has maintained everything according to PRC-005-2) upon regulatory approvals, the entity will have retired PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-17-0 from their program at that time. However, the drafting team believes that the		

Organization	Yes or No	Question 2 Comment
phased Implementation Plan is necessary to avoid any gaps in applicability throughout the maintenance intervals currently in use. Further, to demonstrate continuing compliance, an entity will need evidence that they have been in full compliance with whichever version of the standard was in effect.		
Northeast Power Coordinating Council	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
Duke Energy	Yes	
Dominion	Yes	
Chris Searles	Yes	
Florida Municipal Power Agency	Yes	
Luminant	Yes	
Bonneville Power Administration	Yes	
O&M Group	Yes	
Nebraska Public Power District	Yes	
City of Palo Alto	Yes	

Organization	Yes or No	Question 2 Comment
Bridgeport Energy	Yes	
Beaches Energy Services	Yes	
Puget Sound Energy	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	
American Transmission Company	Yes	
Illinois Municipal Electric Agency	Yes	
Idaho Power Company	Yes	
CenterPoint Energy	Yes	
KCP&L/ KCPL-GMO	Yes	
Midtronics Inc	Yes	

3. **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 offered several suggestions for improvements to the Supplementary Reference and FAQ Document. Punctuation, spelling and content changes have been made to the Supplementary Reference and FAQ Document in response to these suggestions.

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	
Duke Energy	No	
Dominion	No	
Tennessee Valley Authority	No	
Bonneville Power Administration	No	
Nebraska Public Power District	No	
City of Palo Alto	No	
Bridgeport Energy	No	
Puget Sound Energy	No	
Ameren	No	
Ingelside Cogeneration LP	No	

Organization	Yes or No	Question 3 Comment
American Transmission Company	No	
Idaho Power Company	No	
CenterPoint Energy	No	
KCP&L/ KCPL-GMO	No	
Primax Technologies Inc.		In 15.4.1 Frequently Asked Questions, to the question: What did the PSMT SDT mean by “continuity” of the dc supply? One of the proposed methods for ensuring continuity is the following: Specific gravity tests can infer continuity because, without continuity, there could be no charging occurring; and if there is no charging, then specific gravity will go down below acceptable levels. Comment: I agree that the uncharged cell's specific gravity would drop but it would take weeks or months to show. Should power be needed from the battery during this period of time the battery would not be able to perform as it should. To me this an unacceptable risk
Response: Thank you for your comments. The drafting team agrees with you that some methods of detecting continuity are better than others, but the Supplementary Reference and FAQ Document is intended as a general aid to understanding the standard, and not as a strict recommendation of particular maintenance methods. An entity can always do more, or more frequent maintenance if they wish.		
Southwest Power Pool Reliability Standards Development Team	Yes	1. On page 70 of the document we noticed that the word “reakers” was used and would suggest this was intended to be “breakers”. 2. Also on page 81 of the document under the section of “My VRLA batteries have multiple-cells within an individual battery jar (or unit); how am I expected to comply with the cell-to-cell ohmic measurement requirements on these units that I cannot get to?” We would suggest that the wording be changed on “in

Organization	Yes or No	Question 3 Comment
		accessible" to remove the space to give you "Inaccessible".
Response: Thank you for your comments. Punctuation, spelling and content changes have been made to the Supplementary Reference and FAQ Document.		
Chris Searles	Yes	1. In Section 7.1-Frequently Asked Questions, pg 24 - add "or" before "other measurements" inadvertently left out. 2. In Section 8.1.2.4 - 4th & 5th sentences. Consider changing the verbiage: "....The Protection System owner may want to follow the guidelines in the applicable IEEE recommended practices for battery maintenance and testing, especially if the battery in question is used for application requirements in addition to the strict protection and control demands covered under this standard." 3. In section 15.4.1 - (pg 74) "What is the State of Charge...." In the first paragraph on page 74, the first complete sentence, I think the intent is to say "For these two types of batteries, and also for VRLA batteries," . . .
Response: Thank you for your comments. Punctuation, spelling and content changes have been made to the Supplementary Reference and FAQ Document.		
ACES Standards Collaborators	Yes	We suggest that the document should clarify Table 1-4(f). We understand from conversations with drafting team members that not all component attributes have to be met for the exclusion to apply. Rather each component attribute only has to be met individually for the exclusion to apply. We appreciate the drafting team including the localized definitions in the supplementary reference document. However, we believe there is still confusion with the use of component. Component is capitalized within the definition but it is not capitalized throughout the document. We believe the term should be capitalized throughout the document to be clear the localized definition applies. Capitalization of most instances of "system" has been correctly removed since the NERC definition was not consistent with the use. However, there are a few instances where it was removed and should not have been. One example occurs in the second paragraph on page 5 in the red-line document

Organization	Yes or No	Question 3 Comment
		where "system collapse" should be "System Collapse". In the third paragraph on page 5 in the red-line document, "transmission" should be capitalized since the NERC definition would be applicable.
Response: Thank you for your comments. Punctuation, spelling and content changes including your suggestions for capitalization have been made to the Supplementary Reference and FAQ Document. Based on your comment regarding Table 1-4(f), an additional FAQ has been added to Section 15.4.1 of the Supplementary Reference and FAQ Document.		
O&M Group	Yes	(1) We do not agree with no maintenance on the battery monitoring system (2) Also, we do not agree with replacing a battery capacity test by evaluating cell/unit measurements indicative of battery performance against station battery baseline.
Response: Thank you for your comments. **1. Thank you for your comment concerning maintenance on the battery monitoring system. Based on comments concerning the battery Component Attributes in table 1-4(f) a new Frequently Asked Question was added to the Supplementary Reference and FAQ Document. As a part of that FAQ the drafting team gave rational why no maintenance on the battery monitoring system is required by stating "the basis of the exclusions granted in the table is that the monitoring devices must incorporate the monitoring capability of microprocessor based components which perform continuous self-monitoring. For failure of the microprocessor device used in dc supply monitoring, the self-checking routine in the microprocessor must generate an alarm which will be reported within 24 hours of device failure to a location where corrective action can be initiated."** **2. Thank you for your comment concerning battery capacity testing. The drafting team agrees that a performance or modified performance capacity test is the only industry recognized method for determining the actual capacity of a battery. However, the maintenance activity required in the tables of PRC-005-2 is to "Verify that the station battery can perform as manufactured" not to determine the capacity of the battery. For many of the lead acid batteries used in BES Protection Systems, the drafting team believes that evaluating cell/unit measurements indicative of battery performance against a station battery baseline is as a valid method of verifying "that the station battery can perform as manufactured." That is why in Tables 1-4(a) and Tables 1-4(b) owners are allowed to do either of the two listed maintenance activities in their appropriate maximum maintenance intervals to "Verify that the station battery can perform as manufactured."**		

Organization	Yes or No	Question 3 Comment
Western Area Power Administration	Yes	Yes. The standard itself should be more clearly written so that a 100+ page Supplementary Reference and FAQ Document is not needed. This document is also not enforceable, nor is it a standard, so verbiage which interprets the standard and forces requirements should be removed.
Response: Thank you for your comments. This document provides supporting discussion, but is not part of the standard. The drafting team intends that it be posted as a reference document, as expressed in Section F of the standard. The standard is to be a terse statement of requirements, etc., and is not to include explanatory information like that included in the Supplementary Reference and FAQ Document.		
American Electric Power	Yes	On page 82, the text “in accessible” should be correct as “inaccessible”.
Response: Thank you for your comments. Punctuation, spelling and content changes have been made to the Supplementary Reference and FAQ Document.		
Manitoba Hydro	Yes	1. Table of Contents - The drawing should be removed from the Table of Contents. 2. Introduction and Summary: [Page 1] - Should include “Canada”. The sentence should read “The standards are mandatory and enforceable in the United States and Canada”. 3. Protection Systems Product Generations: [page 8] - We suggest changing "control Systems" to "control systems".[Page 28]: “Voltage & Current Sensing Device ...” should be “Voltage and current sensing device ...”[Page 29] "Control Circuit" should not be capitalized.[Page 44] A space is missing: “performance formal-performing segments” should be “performance for mal-performing segments”.[Page 45] "Other problems ..." ascribed to batteries may also apply to other Protection System Components, and therefore does not require special mention for batteries. This paragraph should be removed. 4. [Page 67]: Normally-open contacts of relays 94 & 86 should be treated the same as the current-carrying contacts if they are in use.
Response: Thank you for your comments. Punctuation, spelling and content changes have been made to the Supplementary		

Organization	Yes or No	Question 3 Comment
Reference and FAQ Document. Based on your comment, "Canada" was added to the introductory sentence on page 1 of the Supplementary Reference and FAQ Document. In the case of the normally-open contacts of the 94 and 86, entities may perform more maintenance than is listed within the standard.		
Tacoma Power	Yes	1. On page 88, third bullet, change "auxiliary communications equipment" to "associated communications equipment" for consistency. 2. In Figure A-1, what is meant by "Also verify wiring and test switches"? The emphasis of this question is on 'test switches'.
Response: Thank you for your comments. **1. Punctuation, spelling and content changes have been made to the Supplementary Reference and FAQ Document.** **2. The object of any test in any circuit that has test switches is the same as those tests in similar circuits without test switches. There is no specific mandated test in the standard for "Test Switches," but a test switch might well be a point of failure that one needs to be aware of when performing the mandated routine tests.**		
Illinois Municipal Electric Agency	Yes	Please see response to Question 4.
Response: Thank you for your comments.		
Midtronics Inc	Yes	The paragraphs below are from page 83 of the document (page 89 of the pdf). The first paragraph below contains the words, "risen above" and "over" a baseline. For conductance trending would be going below a baseline. Since this is a technical standard I think there should be a comment noting the difference in trending of conductance as compared to resistance and impedance like it is in the next paragraph. For VRLA batteries, there are two drivers for internal ohmic readings. The first driver is for a means to trend battery life. Trending against the baseline of VRLA cells in a battery string is essential to determine the approximate state of health of the battery. Ohmic measurement testing may be used as the mechanism for measuring

Organization	Yes or No	Question 3 Comment
		the battery cells. If all the cells in the string exhibit a consistent trend line and that trend line has not risen above a specific deviation (e.g. 30%) over baseline, then a judgment can be made that the battery is still in a reasonably good state of health and able to 'perform as manufactured.' It is essential that the specific deviation mentioned above is based on data (test or otherwise) that correlates the ohmic readings for a specific battery/tester combination to the health of the battery. This is the intent of the "perform as manufactured six-month test" at Row 4 on Table 1-4b. The second big driver is VRLA batteries tendency for thermal runaway. This is the intent of the "thermal runaway test" at Row 2 on Table 1-4b. In order to detect a cell in thermal runaway, you need not necessarily have a formal trending program. When a single cell/unit changes significantly or significantly varies from the other cells (e.g. a doubling of resistance/impedance or a 50% decrease in conductance), there is a high probability that the cell/unit/string needs to be replaced as soon as possible. In other words, if the battery is 10 years old and all the cells have approached a significant change in ohmic values over baseline, then you have a battery which is approaching end of life. You need to get ready to buy a new battery, but you do not have to worry about an impending catastrophic failure. On the other hand, if the battery is five years old and you have one cell that has a markedly different ohmic reading than all the other cells, then you need to be worried that this cell is in thermal runaway and catastrophic failure is imminent.
Response: Thank you for your comments. Punctuation, spelling and content changes have been made to the Supplementary Reference and FAQ Document. Based on your comment, the sentence was rewritten as follow: "If all the cells in the string exhibit a consistent trend line and that trend line has not risen above a specific deviation (e.g. 30%) over baseline for impedance tests or below baseline for conductance tests, then a judgment can be made that the battery is still in a reasonably good state of health and able to 'perform as manufactured.'"		
Luminant	Yes	
Southern Company	Yes	

4. 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: Other than as noted below, no changes were made to the standard in response to comments in Question 4.

Commenters continued to object to Applicability 4.2.1 in contrast to the interpretation in PRC-005-1b. The drafting team explained their position relative to this objection, and added discussion in Section 2.3.1 of the Supplementary Reference and FAQ Document to further explain their position.

Several commenters objected to various VSLs, particularly as it relates to the Lower VSL for Requirement R3. The drafting team explained that the VSLs are established in accordance with the VSL Guidelines. However, a minor editorial change was made to all levels of VSL for Requirement R5.

Several commenters continued to object to inclusion of UFLS and UVLS relays, in that they may not be installed on BES equipment. The drafting team responded that these devices, while not on BES equipment, are installed for the reliability of the BES, and are therefore included. The drafting team further noted that these devices are currently addressed in PRC-008-0 and PRC-011-0.

Several commenters questioned the inclusion of breaker trip coil verification, auxiliary relay verification, and/or lockout relay verification. The drafting team responded that each of these devices needs to be maintained at the prescribed intervals to assure reliability.

A few comments were offered on unresolved maintenance issues, various aspects of battery maintenance, communications system batteries, performance-based maintenance program criteria, and sudden pressure relay dc circuit testing. The drafting team provided responses to each of these comments, explaining the importance of the requirements within the standard.

Organization	Yes or No	Question 4 Comment
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

Organization	Yes or No	Question 4 Comment
		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.
Response: Thank you for your comments. **1. The drafting team 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." The drafting team has added a discussion to Section 2.3.1 of the Supplementary Reference and FAQ Document explaining their intent regarding the Applicability.** **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 drafting team sees no appreciable improvement in the standard with your proposed change, and respectfully declines to modify the standard.**		
Ameren		Ameren supports PRC-005-2 in the interest of BES reliability. We also appreciates the SDT's overall high quality product and looks forward to its implementation; however, we still assert that 1) the zero tolerance approach, in this case involving significantly large number (thousands) of devices, is an impractical requirement, 2) the VRF for R3 should be Medium, and 3) maintenance records for replaced equipment should not be retained. We' have raised these concerns and justified our position repeatedly but yet not convinced the SDT to change their position.
Response: Thank you for your comments. **1. The NERC VSL Guidelines do not allow some level of non-performance without being in violation.**		

Organization	Yes or No	Question 4 Comment
2. The drafting team believes that the assigned VRF is correct, in that that failure to implement and follow its PSMP could cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures. **3. The drafting team 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, to determine compliance. This seems to be consistent with what auditors are expecting (per the drafting team's experience), and is also consistent with Compliance Process Bulletins 2011-001 and 2009-05.**		
Florida Municipal Power Agency		1. Applicability does not align with previously approved interpretation of "transmission Protection System", Appendix 1 of the current V1 standard, that basically says that protection systems applicable to the standard are those that both "detect faults" and "trip" BES equipment. Applicability 4.2.1 says: "Protection Systems that are installed for the purpose of detecting Faults on BES Elements", which does not match "and" relationship of the interpretation. Eliminating this "and" relationship will cause distribution protection to be swept into the standards, such as reverse power relays designed to "detect" faults on the transmission system but "trip" distribution breakers. Distribution is expressly excluded in Section 215 and these types of relays have no impact on BES reliability. 2. Zero defect approach, should move to what CIP v5 is moving towards of internal controls rather than strict 100% compliance, or even better, a Total Quality Management approach. 3. UFLS and UVLS testing - broaches on distribution which is expressly excluded from Section 215 jurisdiction - when discussing control circuit testing, instrument transformer testing, etc.. We believe the requirement should be relay-only testing. We also believe that the incremental benefit is not worth the increased costs, e.g., one UFLS relay not operating has insignificant impact on a UFLS event; whereas one relay not operating to clear a fault has significant impact.
Response: Thank you for your comments. **1. The drafting team believes the Applicability as stated in PRC-005-2 is correct and supports the reliability of the BES. The**		

Organization	Yes or No	Question 4 Comment
		drafting team 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." The drafting team has added a discussion to Section 2.3.1 of the Supplementary Reference and FAQ Document explaining their intent regarding the Applicability. 2. The NERC VSL guidelines do not allow some level of non-performance without being in violation. 3. FPA Section 215(a) definitions section defines bulk-power system as: "(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)." That definition then is limited by a later statement which adds the term bulk-power System: "… does not include facilities used in the local distribution of electric energy." Also, Section 215 also covers users, owners, and operators of bulk-power facilities. UFLS and UVLS (when the UVLS is installed to prevent system voltage collapse or voltage instability for BES reliability) are not "used in the local distribution of electric energy," despite their location on local distribution networks. Further, if UFLS/UVLS facilities were not covered by the Reliability Standards, then in order to protect the integrity of the BES during under-frequency or under-voltage events, that load would have to be shed at the transmission bus to ensure the load-generation balance and voltage stability is maintained on the BES.
Beaches Energy Services		1. Applicability does not align with previously approved interpretation of "Transmission Protection System", Appendix 1 of the current V1 standard, that basically says that protection systems applicable to the standard are those that both "detect faults" and "trip" BES equipment. Applicability 4.2.1 says: "Protection Systems that are installed for the purpose of detecting Faults on BES Elements", which does not match "and" relationship of the interpretation. Eliminating this "and" relationship will cause distribution protection to be swept into the standards, such as reverse power relays designed to "detect" faults on the transmission system but "trip" distribution breakers. Distribution is expressly excluded in Section 215 and these types of relays have no impact on BES reliability. 2. Zero defect approach, should move to what CIP v5 is moving towards of internal controls rather than strict 100% compliance, or even better, a Total Quality

Organization	Yes or No	Question 4 Comment
		Management approach. 3. UFLS and UVLS testing - broaches on distribution which is expressly excluded from Section 215 jurisdiction - when discussing control circuit testing, instrument transformer testing, etc.. We believe the requirement should be relay-only testing. We also believe that the incremental benefit is not worth the increased costs, e.g., one UFLS relay not operating has insignificant impact on a UFLS event; whereas one relay not operating to clear a fault has significant impact.
Response: Thank you for your comments. 1. **The drafting team believes the Applicability as stated in PRC-005-2 is correct and supports the reliability of the BES. The drafting team 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." The drafting team has added a discussion to Section 2.3.1 of the Supplementary Reference and FAQ Document explaining their intent regarding the Applicability.** 2. **The NERC VSL guidelines do not allow some level of non-performance without being in violation.** 3. **FPA Section 215(a) definitions section defines bulk-power system as: "(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)." That definition then is limited by a later statement which adds the term bulk-power system: "... does not include facilities used in the local distribution of electric energy." Also, Section 215 also covers users, owners, and operators of bulk-power facilities.** **UFLS and UVLS (when the UVLS is installed to prevent system voltage collapse or voltage instability for BES reliability) are not "used in the local distribution of electric energy," despite their location on local distribution networks. Further, if UFLS/UVLS facilities were not covered by the Reliability Standards, then in order to protect the integrity of the BES during under-frequency or under-voltage events, that load would have to be shed at the transmission bus to ensure the load-generation balance and voltage stability is maintained on the BES.**		
Illinois Municipal Electric Agency		As indicated in previous comments, Illinois Municipal Electric Agency (IMEA) appreciates SDT efforts, and supports the overall refinements in PRC-005-2. However, IMEA respectfully disagrees with the SDT's decision to not resolve the

Organization	Yes or No	Question 4 Comment
		inconsistency between 4.2.1 and the FERC-approved interpretation in PRC-005-1b. Whether the term “transmission Protection System” is used in PRC-005-2, as indicated in the SDT response to our comments, is not the point. The interpretation in PRC-005-1b provides clarity to smaller entities in particular regarding which protective devices need to be factored into compliance with PRC-005 (and other PRC standards). This inconsistency should have been more clearly vetted within the industry given the fact that this was a recently NERC- and FERC-approved Protection System interpretation which was being compromised by the proposed language in 4.2.1. Once again, we find ourselves aiming at a constantly moving compliance target. This issue has the potential to require more DPs to comply with PRC-005, and draw more small entities into registration, which of course would require increased resource expenditures associated with compliance. This issue does not appear to be consistent with NERC and FERC efforts to minimize the impact on smaller entities that have minimal or no potential to impact the BES. If the 4.2.1 language was carefully considered so as not to unnecessarily impact small entities, it would be appreciated that these provisions be more clearly addressed in the "Supplementary Reference and FAQ". Thank you for this opportunity to comment. This issue is significant enough that IMEA felt a Negative vote was unfortunately necessary on an otherwise significant improvement to PRC-005.
Response: Thank you for your comments. **The drafting team believes that the Applicability 4.2.1 as stated in PRC-005-2 is correct and supports the reliability of the BES. The drafting team 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 drafting team 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. The drafting team has added a discussion to Section 2.3.1 of the Supplementary Reference and FAQ Document explaining their intent regarding the Applicability.**		
American Transmission Company		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 4 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. Interrupting devices with multiple trip coils operate the same mechanism. Therefore, by requiring testing of each trip coil in a redundant system you double the amount of times the system is out of its desired state without increasing the performance of the device. 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 definition of Protection System includes trip coils within the dc control circuitry component, and it is necessary to perform maintenance on all of these devices to assure proper performance. Performance-based maintenance is an option to increase the intervals if the performance of these devices supports those intervals.		
Bonneville Power		BPA appreciates that the Standards Development Team does not believe that communications batteries are included in PRC-005-2 standard. While BPA believes

Organization	Yes or No	Question 4 Comment
Administration		the SDT did not intend to include communications batteries in the standard, this intention is neither captured by the language of the standard nor explicit in the Supplementary Reference and FAQ document. Ambiguity on regulation of communications batteries provides no benefit and comprises a concrete regulatory risk to BPA during an audit. BPA strongly believes that the standard should articulate exactly what types and applications of batteries it means to regulate and which batteries it does not.
Response: Thank you for your comments. The drafting team believes this issue is addressed in the response to FAQ: "Does this standard refer to Station batteries or all batteries; for example, Communications Site Batteries?" in the Supplementary Reference and FAQ Document.		
CenterPoint Energy		CenterPoint Energy recommends that PRC-005-2 include a built-in tolerance and move away from a zero-defect enforcement model. Achieving one-hundred percent schedule and documentation compliance is negatively impacting resources on an industry-wide basis for the sake of the "last one percent" and is not needed to provide an adequate level of BES reliability. Entities should be allowed the opportunity to correct minor deficiencies discovered in the program via customary mitigation activities as part of an internal controls policy and good utility practice instead of via the enforcement channel. One possible avenue for incorporating such a tolerance into the Standard is to establish a threshold for the Lower VSL. For example, the Lower VSL for requirement R3 could state: "For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 1% but 5% or less of the total Components included within a specific Protection System Component type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.".
Response: Thank you for your comments. The drafting team believes that the assigned VSLs are correct. The SDT believes that failure to implement and follow a PSMP could cause or contribute to Bulk Electric System instability, separation, or a Cascading		

Organization	Yes or No	Question 4 Comment
sequence of failures. Anything less than 100% should be a violation.		
NIPSCO		Comment: Test and maintenance data requirements need to be specific and not open to interpretation. Examples: 1. The number of data points required on an impedance circle graph for a relay calibration versus maximum torque angle only.2. Verification of inputs into microprocessor relay records to include magnitude or is a check box sufficient.
Response: Thank you for your comments. The drafting team believes it has struck the appropriate balance in affording some freedom in applying the standard by Transmission Owners, while minimizing the possibility of adverse auditing interpretations.		
Duke Energy		Duke Energy votes “Negative” because we strongly object to the wording in the Applicability section 4.2.1 which expands 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. 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. 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. 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.” Duke Energy proposes the following wording for Section 4.2.1: “Protection Systems that are installed for the purpose of protecting BES

Organization	Yes or No	Question 4 Comment
		Elements (lines, buses, transformers, etc.)".
Response: Thank you for your comments. The drafting team still believes that the Applicability as stated in PRC-005-2 is correct, that it supports the reliability of the BES, and that 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 drafting team 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.		
Nebraska Public Power District		1. Keeping records after the end of the audit period does not increase the current reliability of the electric grid. Requiring records to be kept for longer time periods will increase the risk to utilities of making a mistake in their record keeping and receiving a fine due to the zero tolerance policy drafted in the standard. Records beyond the audit period, up to 24 years old, don't have any effect on the reliability of the current bulk electric system. 2. 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. 3. We recommend removing requirement 5. This is adding the requirement for a 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:-A Countable event has already been defined in the definition of terms, which would cover the need to replace equipment. -The quantity and causes of Misoperations are a direct correlation to good or poor maintenance practices and corrective actions by a utility. -TADS records events which are initiated by failed protection system equipment and would identify utilities with poor corrective action processes.

Organization	Yes or No	Question 4 Comment

Response: Thank you for your comments.

1. **In order that a Compliance Monitor can be assured of compliance, the drafting team believes that the Compliance Monitor will need the data of the most recent performance of the maintenance, as well as the data of the preceding one to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The drafting team has specified the data retention in the posted standard to establish this level of documentation. This seems to be consistent with what auditors are expecting (per the drafting team's experience), and is also consistent with Compliance Process Bulletins 2011-001 and 2009-05. The entity is urged to assure that data is retained as specified within the standard.**
2. **The drafting team 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.**
3. **The drafting team respectfully disagrees:**

it's the drafting team believes 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 drafting team 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 six-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 six-calendar-month requirement for this maintenance activity. The drafting team does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible 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 action is being undertaken.

Organization	Yes or No	Question 4 Comment
Manitoba Hydro		1. 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. 2. Additionally, Standard PRC-005-2:R3: "minimum maintenance activities" is not specified in the Tables. We suggest removing the word "minimum". 3. R5: It is not clearly stated that the Unresolved Maintenance issues must be identified. As written, only "identified Unresolved Maintenance Issues" are applicable in R5. 4. Measure M1: “responsible entity(s)” is not defined in the standard. The format of examples is inconsistent with the other measures. We suggest replacing "... (such as ... drawings) ..." with "The evidence may include, but is not limited to, manufacturer's specifications or engineering drawings. ...". 5. Evidence Retention: There is no statement in either the requirements or the measures regarding a "dated" PSMP. 6. VSL: a. R3 - "minimum maintenance activities" is not specified in the Tables. We suggest removing the word "minimum". b. R5 - We suggest "identified Unresolved Maintenance Issues" to agree with the wording in R5. 7. Table 1.1: The Maintenance Activities statement "For all unmonitored relays:" is redundant since it is specified in the Component Attributes. 8. Table 3: Voltage and current sensing devices for UFLS or UVLS should be excluded from periodic maintenance if they are connected to microprocessors relays with AC measurements continuously verified with alarming, as provided for voltage and current sensing devices in Table 1-3. 9. The wording "Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system" is unclear. It is unclear if "used only for a UFLS or UVLS system" applies to the "Protection System dc supply" or to the "non-BES interrupting devices". Exclusions in Table 1-4(f) which pertain to verifying dc supply voltage should also apply to the dc supply in Table 3.

Organization	Yes or No	Question 4 Comment
		10. Attachment A a. To maintain the technical justification Item 5: for consistency with Item 4 and the VSL, we suggest changing the wording to “If the Components in a Protection System Segment maintained through a performance-based PSMP experience more than 4% Countable Events, develop, document, and implement an action plan to reduce the Countable Events to no more than 4% of the Segment population within 3 years. b. "Technical Justification: "Other problems ..." [page 7] ascribed to batteries may also apply to other Components, and therefore does not require special mention for batteries. This paragraph should be removed. c. Pages 12 to 13 - The numbering should agree with the standard. d. Item 10 [page 13] - For consistency with the previous item and the VSL, we suggest changing the wording to "If the Components in a Protection System Segment maintained through a performance-based PSMP experience more than 4% Countable Events, develop, document, and implement an action plan to reduce the Countable Events to no more than 4% of the Segment population within 3 years." 11. The bullet “All of the relevant communication system tests still apply” was added in examples 1 and 2 on pages 68 and 69 of the Supplementary Reference and FAQ - Draft PRC0005-2 Protection System Maintenance (JULY 2012) document (SRFAQ). This makes reference to Table 3 (page 26) of the Standard, but Table 3 does not identify communication systems as a Component Attribute. Table 1-2 (Communications Systems) on page 14 of the standard also excludes the UFLS and UVLS equipment on Table 3. Section 15.7, page 91, of the SRFAQ document also states “No maintenance activity is required for associated communication systems for distributed UFLS and distributed UVLS schemes”. I believe that since no communications systems has been identified in Table 3, this bullet cannot be added to the examples identified above in the SRFAQ document. 12. Implementation Plan: Should entities be given a single compliance date for each of the maintenance intervals, and be allowed the flexibility to schedule and

Organization	Yes or No	Question 4 Comment
		complete their maintenance as required while transitioning to the defined time intervals in PRC-002-2. For example, if a maximum maintenance interval is 6 calendar years, should the implementation plan only require that “The entity shall be 100% compliant on the first day of the first calendar quarter 84 months following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter 96 months following Board of Trustees adoption.”? The existing standard PRC-005-1 already requires protection systems to be maintained as part of a program. Prescribing how an entity must reach full compliance may provide a negligible improvement in reliability, while significantly increasing the compliance burden. PRC-005-2 affects a large number of assets, and proving compliance for prescribed percentages of assets during the transition period may create unnecessary overhead with little added value.

Response: Thank you for your comments.

1. **The drafting team has not changed its position from that expressed in response to the earlier comments.**
2. **Requirement R3 establishes that the maintenance activities specified in the Table are minimum maintenance activities.**
3. **The drafting team believes it is implicit that Unresolved Maintenance issues must be identified.**
4. **The term, “responsible entities” is used throughout NERC standards, and pertains to the applicable entities specified in a particular requirement. The drafting team suggests that the evidence for Measure M1 is sufficiently variable that the term “may include but is not limited to” would not be appropriate.**
5. **The drafting team believes it is self-evident that compliance documents must be dated in order that the time period to which they apply is clear.**
6. **Requirement R3 establishes that the maintenance activities specified in the Table are minimum maintenance activities, and therefore apply to the related VSL. The drafting team has added “identified” to the Requirement R5 VSL table.**
7. **The drafting team believes that the word “unmonitored” is still required for clarity in Table 1-1.**
8. **The drafting team observes that the third row of Table 3 (protective relays) addresses your suggestion.**

Organization	Yes or No	Question 4 Comment
9. The drafting team believes that the wording in Table 3, third row of component attributes is clear and is applicable only to dc supplies used for distributed UFLS and distributed UVLS systems. 10. The drafting team does not believe that your suggested changes improve the standard and declines to make the changes. 11. The drafting team has modified the Supplementary Reference and FAQ Document to remove the reference to the communication system in these two locations. 12. The drafting team believes that implementation of the standard according to the milestones established within the Implementation Plan is necessary to establish an effective ongoing Protection System Maintenance Program and to demonstrate a commitment to implementing the new standard.		
Dominion		Page 11 of the PRC-005-2 redline standard, Version History; Previous versions (i.e. 0, 1, 1a, 1b) need to be included here.
Response: Thank you for your comments. The Version History is intended to capture changes between the last-approved version of the standard and the new standard being proposed.		
ReliabilityFirst		ReliabilityFirst thanks the SDT for changing the maximum time for unmonitored systems within Table 1-2 back to six years. However, RFC continues to believe the language in Requirement R5 ("...shall demonstrate efforts to correct...") is subjective and will be hard to measure. RFC believes at a minimum, the applicable entity should be required to develop a Corrective Action Plan to address the Unresolved Maintenance Issue. Without the formality and burden of a full-fledged Corrective Action Plan, ReliabilityFirst is concerned the identified Unresolved Maintenance Issues may not get resolved or resolved in a timely manner. 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. As to demonstrating efforts to address Unresolved Maintenance Issues, the drafting team's intent is to furnish a way for an entity to address Unresolved Maintenance Issues without the formality and burden of a		

Organization	Yes or No	Question 4 Comment
full-fledged Corrective Action Plan.		
Puget Sound Energy		1. Sealed Battery Maintenance: The requirement of impedance testing the batteries every 6 months seems excessive based on our experience. We have been successfully maintaining our sealed cells with impedance testing at 36 months. 2. CT testing on Neutrals: The requirement to verify operation is not possible on the Neutral CT as they don't normally carry current. There should be a clarification that verification of readings can only occur (and is only required) on phase CT's and the neutral CT is excluded. 3. Dual Trip Coil Check: In our experience the requirement to verify operation of both trip coils through a trip is overly burdensome and does not improve the reliability of the system. Testing to verify operation of the output relays, proper tripping of the breaker, and verification of trip coil continuity is sufficient to verify the protective system will operate appropriately. 4. Breaker Failure Relay Testing: In our experience testing of the breaker failure relay up to the relay outputs is sufficient to ensure proper operation. The tripping of the breakers through the coils is maintained through the individual relay maintenance. Requiring clearing of the main bus during maintenance is not practical and may negatively impact the reliability of the Bulk Electric System.
Response: Thank you for your comments. **1. The drafting team believes that the six-month interval is proper for VRLA batteries.** **2. See discussion in Section 8.1.3 of the Supplementary Reference and FAQ Document.** **3. The definition of Protection System includes trip coils within the dc control circuitry component, and it is necessary to perform maintenance on all of these devices to assure proper performance. Performance-based maintenance is an option to increase the intervals if the performance of these devices supports those intervals.** **4. The standard does not require that the bus be cleared for breaker failure relay testing, but does require that the circuitry from the output of breaker failure relays be verified to the intended target (trip coil, lockout relay coil, input to another relay, etc). The use of test switches or trip cutout switches may be used to break the control circuit into manageable portions so the circuitry can be verified using overlapping zones without necessitating that all associated breakers be tripped for each**		

Organization	Yes or No	Question 4 Comment
maintenance activity.		
ACES Standards Collaborators		The drafting team has done an outstanding job refining the standard. Because no standard will ever be perfect, we believe industry and reliability would be best served to move the standard to recirculation ballot at this point. Regarding Requirement R1 VSLs, we continue to believe that missing three component types should not jump to a Severe VSL when missing two is a Moderate VSL. Missing three should be a High VSL.
Response: Thank you for your response. **The drafting team believes that missing three Protection System component types (out of five) meets the definition of a Severe VLS in the VSL Guidelines.**		
City of Palo Alto		These comments supercede the comments submitted earlier by Tom Finch by mistake. Attachment A "Criteria for a Performance-Based Protection System Maintenance Program" requires a minimum segment population of 60 Components in order to justify a PSMP. We feel the 60 component requirement is arbitrary and discriminates against small entities such as Palo Alto which do not have 60 components and may wish to implement a performance-based PSMP. We feel the decision on whether to use a time-based or performance-based PSMP should be made by the Entity and not NERC.
Response: Thank you for your comment. The minimum population of 60 components, as described in Section 9.1 of the Supplemental Reference and FAQ Document, is a statistically-significant sample size to meet the performance goals of the performance-based maintenance program. Section 9.2 of the Supplemental Reference and FAQ Document suggests that small entities may be able to pool their component populations with other small entities to establish a common performance-based maintenance program.		
Tennessee Valley Authority		TVA appreciates the work that the standard drafting team has done on PRC-005-2.

Organization	Yes or No	Question 4 Comment
		As stated in our comments on Draft 3, TVA is concerned with the maximum maintenance interval of 4 calendar months specified for unmonitored communications systems in Table 1-2, and for that reason has voted negative. A longer implementation timeframe is needed for replacement of the unmonitored units.
Response: Thank you for your comments. The drafting team suggests that performance-based maintenance is an option to increase the intervals if the performance of these devices supports those intervals. 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.		
Southwest Power Pool Reliability Standards Development Team		We have a concern that the RE would have difficulty in implementation of the phased in approach. We would suggest extensive training for the auditors for this standard and others which have these multi phased approaches to implementation. With this training it would also be beneficial if NERC would hold a webinar to fill in the industry on the training provided to keep everyone on the same page. We would like to also suggest that NERC compliance staff work with the Drafting Team to develop the RSAWs for this standard.
Response: Thank you for your comments. The drafting team believes that implementation of the standard according to the milestones established within the Implementation Plan is necessary to establish an effective ongoing Protection System Maintenance Program and to demonstrate a commitment to implementing the new standard. The drafting team will pass your suggestion for auditor training and webinar on to NERC Compliance staff. The current NERC RSAW development process encourages that NERC staff involve drafting team representatives when developing RSAWs.		
Southern Company		We strongly suggest that the SDT modify the Applicability section to clarify that Sections 4.2.1 thru 4.2.4 apply to transmission and distribution facilities, and that Section 4.2.5 defines the generator owner applicability by making changes similar to these proposed below. Without this distinctive change, there exists an ability to mis-interpret Section 4.2.1 such that auditors may apply this standard to a generation scope wider than is specified in the NERC Statement of Registry Criteria (Rev 5). We

Organization	Yes or No	Question 4 Comment
		propose the following changes to 4.2.1 thru 4.2.4:1) Replace the existing 4.2.1 with “Protection Systems for transmission and distribution Facilities, including:”2) Move the existing 4.2.1 thru 4.2.4 to subparts of the new 4.2.1 as 4.2.1.1, 4.2.1.2, 4.2.1.3, 4.2.1.4.
Response: Thank you for your comments. **Protection Systems that are installed in non-BES facilities for the purpose of detecting faults on the BES are included in this standard. The drafting team intends that Applicability 4.2.1 address non- generator BES elements. The drafting team has added a discussion to Section 2.3.1 of the Supplementary Reference and FAQ Document explaining their intent regarding the Applicability.**		
Western Area Power Administration		Western feels that our comments and concerns as provided on the previous comment form were not adequately addressed. Those comments are repeated below: 1. Western Area Power Administration is appreciative of the hard work done by the SDT and NERC. We respectfully submit our professional opinion that the increased relay testing 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. 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 ensuring reliability is to leave it alone. 2. 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. 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

Organization	Yes or No	Question 4 Comment
		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. 3. 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. Do not use the FAQ to modify the standard. The FAQ should strictly be used for clarification only. A standard that relies on a lengthy FAQ and multiple CAN's needs to be re-written concisely and clearly.
Response: Thank you for your comments **1. The drafting team recognizes the risk of human error trips when performing maintenance but believes these risks can be managed. Auxiliary relays must be maintained every 12 years, and may be included within the 12-year unmonitored control circuitry verification. Performance-based maintenance is an option if you want to extend your intervals beyond 12 years.** **2. The drafting team believes that electromechanical lockout relays need periodic operation and that they need to be exercised at the same six-year interval required for electromechanical relays. Performance-based maintenance is an option if you want to extend your intervals beyond six years.** 3. **The need to verify the path from the sudden pressure relay trip contact through the auxiliary seal in and through to the lockout relay coil is clearly within the scope of PRC-005-2 as part of the Protection System control circuitry. The sensing element is omitted from PRC-005-2 testing requirements because the drafting team is unaware of industry-recognized activities or intervals for the sensing elements. The drafting team believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1b and consistent with the SAR for Project 2007-17. However, a future revision of PRC-005 will likely add sudden pressure relays in response to directives from FERC Order 758. The Supplementary Reference and FAQ Document provides supporting discussion and clarification but does not modify the standard in any way. The standard is drafted such that the requirements are fully stated; however, the entire field of maintenance of Protection Systems is sufficiently complex that that the drafting team has provided the Supplementary Reference and FAQ Document to share effective methods of meeting the requirements (as anticipated by the drafting team) and to share the drafting team's rationale in establishing the required maximum intervals and minimum activities.**		
O&M Group		None

Organization	Yes or No	Question 4 Comment
Idaho Power Company		None

END OF REPORT