Consideration of Comments on 2nd Draft of the Standard for Protection System Maintenance and Testing Project 2007-17

The Protection System Maintenance and Testing Standard Drafting Team thanks all commenters who submitted comments on the 2nd draft of the PRC-005-2 standard for Protection System Maintenance and Testing. This standard was posted for a 45-day public comment period from June 11, 2010 through July 16, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 58 sets of comments, including comments from more than 130 different people from over 70 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Many commenters objected to the establishment of maximum allowable intervals and offered comments on most of the individual activities and intervals within the Tables.

- The SDT responded that "FERC Order 693 and the approved SAR assigned the SDT to develop a Standard with maximum allowable intervals and minimum maintenance activities."

To provide more clarity, the SDT completely rearranged and revised the Tables.

- The Tables now consist of one table for each of the five Protection System component types, as well as a sixth table to address monitoring and alarming requirements to support extended intervals for monitored Protection System components.

Many commenters disagreed with some of the VRF and VSL assignments.

- The SDT made several modifications to the VRFs and VSLs that are in-keeping with the guidance provided by NERC and FERC.

Other comments were offered regarding Time Horizons, resulting in modification of the Time Horizons for both R3 and R4 from Long-Term Planning to Operations Planning.

In response to suggestions relative to the Measures, the SDT made changes to all four Measures.

Commenters were appreciative for the information contained in the two reference documents, but indicated a preference for some of the information to be included within the body of the Standard.

- In response, the SDT included the definitions of those terms exclusive to this standard, specifically "component type", "component", "segment", "maintenance correctable issue", and "countable event", within the Standard.

In this report, comments have been organized by question number. Comments can be viewed in their original format on the following web 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 and Director of Standards, Herbert Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

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

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Joseph DePoorter	MRO's NERC Standards Review Subcommittee (NSRS)										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	WPSC	MRO	3, 4, 5, 6
4.	Jason Marshall	MISO	MRO	2
5.	Jodi Jenson	WAPA	MRO	1, 6
6.	Ken Goldsmith	ALTW	MRO	4
7.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
8.	Eric Ruskamp	LES	MRO	1, 3, 5, 6
9.	Joseph Knight	GRE	MRO	1, 3, 5, 6
10.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
11.	Scott Nickels	RPU	MRO	4
12.	Terry Harbour	MEC	MRO	6, 1, 3, 5

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
13. Carol Gerou	MRO	MRO	10										
2.	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.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity 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.	Ben Eng	New York Power Authority	NPCC	4
8.	Brian Evans-Mongeon	Utility Services	NPCC	8
9.	Dean Ellis	Dynegy Generation	NPCC	5
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1
13.	Michael R. Lombardi	Northeast Utilities	NPCC	1
14.	Randy MacDonald	New Brunswick System Operator	NPCC	2
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Chantel Haswell	FPL Group	NPCC	5
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Saurabh Saksena	National Grid	NPCC	1
20.	Michael Schiavone	National Grid	NPCC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

21.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
22.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Steve Alexanderson	Pacific Northwest Small Public Power Utility Comment Group			X	X						

	Additional Member	Additional Organization	Region	Segment Selection
1.	Russ Noble	Cowlitz PUD	WECC	3, 4, 5
2.	Dave Proebstel	Clallam County PUD	WECC	3
3.	John Swanson	Benton PUD	WECC	3
4.	Steve Grega	Lewis County PUD	WECC	3, 4

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Margaret Ryan	PNGC Power			X					X		

	Additional Member	Additional Organization	Region	Segment Selection
1.		Blachly-Lane Electric Cooperative	WECC	3
2.		Central Electric Cooperative	WECC	3
3.		Clearwater Electric Cooperative	WECC	3
4.		Consumer's Power Company	WECC	3
5.		Coos-Curry Electric Cooperative	WECC	3
6.		Douglas Electric Cooperative	WECC	3
7.		Fall River Electric Cooperative	WECC	3
8.		Lane Electric Cooperative	WECC	3
9.		Lincoln Electric Cooperative	WECC	3
10.		Lost River Electric Cooperative	WECC	3
11.		Northern Lights Electric Cooperative	WECC	3
12.		Okanogan Electric Cooperative	WECC	3
13.		Raft River Electric Cooperative	WECC	3

		Commenter	Organization	Industry Segment 1	2	3	4	5	6	7	8	9	10

14.		Salmon River Electric Cooperative	WECC	3
15.		Umatilla Electric Cooperative	WECC	3
16.		West Oregon Electric Cooperative	WECC	3
17.		PNGC	WECC	8

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Russell Hardison	TOM Support Manager	SERC	
2.	Pat Caldwell	TOM Support	SERC	
3.	David Thompson	GO	SERC	
4.	Jim Miller	GO	SERC	

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dean Bender	BPA, Tx SPC Technical Svcs	WECC	1
2.	John Kerr	BPA, Tx Technical Operations	WECC	1
3.	Mason Bibles	BPA, Tx Sub Maint and HV Engineering	WECC	1
4.	Laura Demory	BPA, Tx PSC Technical Svcs	WECC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Kenneth D. Brown	Public Service Enterprise Group ("PSEG Companies")	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Hubertus	PSE&G	RFC	1, 3
2.	Scott Slickers	PSEG Power Connecticut	NPCC	5
3.	Jim Hebson	PSEG ER&T	ERCOT	5, 6
4.	Dave Murray	PSEG Fossil	RFC	5

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

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6
2.	Jim Kinney	FE	RFC	1
3.	K. Dresner	FE	RFC	5
4.	B. Duge	FE	RFC	5
5.	J. Chmura	FE	RFC	1
6.	B. Orians	FE	RFC	5

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	S. Tom Abrams	Santee Cooper	SERC	1
2.	Rene' Free	Santee Cooper	SERC	1
3.	Bridget Coffman	Santee Cooper	SERC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Daniel Herring	The Detroit Edison Company			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dave Szulczewski	Relay Engineering	RFC	3, 4, 5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Sasa Maljukan	Hydro One Networks	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Peter FALTAOUS	Hydro One Networks, Inc.	NPCC	1
2.	David Kiguel	Hydro One Networks, Inc.	NPCC	1
3.	Paul DIFILIPPO	Hydro One Networks, Inc.	NPCC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Annette M. Bannon	PPL Supply					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mark A. Heimbach	PPL Martins Creek, LLC	RFC	5
2.	Joseph V. Kisela	PPL Lower Mount Bethel Energy, LLC	RFC	5

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

3.		PPL Brunner Island, LLC	RFC	5
4.		PPL Montour, LLC	RFC	5
5.		PPL Holtwood, LLC	RFC	5
6.		PPL Wallingford, LLC	NPCC	5
7.		PPL University Park, LLC	RFC	5
8.	David L. Gladey	PPL Susquehanna, LLC	RFC	5
9.	Thomas E. Lehman	PPL Montana, LLC	WECC	5
10.	Lloyd R. Brown	PPL Montana, LLC	WECC	5
11.	Augustus J. Wilkins	PPL Montana, LLC	WECC	5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Richard Kafka	Pepco Holdings, Inc. - Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alvin Depew	Potomac Electric Power Company	RFC	1
2.	Carl Kinsley	Delmarva Power & Light	RFC	1
3.	Rob Wharton	Delmarva Power & Light	RFC	1
4.	Evan Sage	Potomac Electric Power Company	RFC	1
5.	Carlton Bradsaw	Delmarva Power & Light	RFC	1
6.	Jason Parsick	Potomac Electric Power Company	RFC	1
7.	Walt Blackwell	Potomac Electric Power Company	RFC	1
8.	John Conlow	Atlantic City Electric	RFC	1
9.	Randy Coleman	Delmarva Power & Light	RFC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Individual	JT Wood	Southern Company Transmission	X		X							
15.	Individual	Silvia Parada Mitchell	Corporate Compliance	X				X	X				
16.	Individual	Jana Van Ness, Director Regulatory Compliance	Arizona Public Service Company	X		X		X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
17.	Individual	Tom Schneider	WECC										X
18.	Individual	Brandy A. Dunn	Western Area Power Administration	X					X				
19.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
20.	Individual	John Canavan	NorthWestern Corporation	X									
21.	Individual	Dan Roethemeyer	Dynegy Inc.					X					
22.	Individual	Robert Ganley	Long Island Power Authority	X									
23.	Individual	Jonathan Appelbaum	The United Illuminating Company	X									
24.	Individual	Lauri Dayton	Grant County PUD	X				X					
25.	Individual	Mark Fletcher	Nebraska Public Power District	X		X		X					
26.	Individual	Brian Evans-Mongeon	Utility Services								X		
27.	Individual	Charles J.Jensen	JEA	X		X		X					
28.	Individual	Fred Shelby	MEAG Power	X		X		X					
29.	Individual	James A. Ziebarth	Y-W Electric Association, Inc.				X						
30.	Individual	Armin Klusman	CenterPoint Energy	X									
31.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
32.	Individual	Edward Davis	Entergy Services	X		X		X	X				
33.	Individual	James Sharpe	South Carolina Electric and Gas	X		X		X	X				
34.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
35.	Individual	Jeff Nelson	Springfield Utility Board			X							
36.	Individual	Amir Hammad	Constellation Power Generation					X					
37.	Individual	Gerry Schmitt	BGE	X									
38.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
39.	Individual	Jeff Kukla	Black Hills Power	X		X		X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
40.	Individual	John Bee	Exelon	X		X		X					
41.	Individual	Andrew Z.Pusztai	American Transmission Company	X									
42.	Individual	Thad Ness	American Electric Power	X		X		X	X				
43.	Individual	Barb Kedrowski	We Energies			X	X	X					
44.	Individual	Jianmei Chai	Consumers Energy Company			X	X	X					
45.	Individual	Art Buanno	ReliabilityFirst Corp.										X
46.	Individual	Tyge Legier	San Diego Gas & Electric	X		X		X					
47.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
48.	Individual	Claudiu Cadar	GDS Associates	X									
49.	Individual	Kirit Shah	Ameren	X		X		X	X				
50.	Individual	Joe Knight	Great River Energy	X		X		X	X				
51.	Individual	Terry Bowman	Progress Energy Carolinas	X		X		X	X				
52.	Group	Joe Spencer - SERC staff and Phil Winston - PCS co-chair	SERC Protection and Control Sub-committee (PCS)										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Nauert	Ameren Services Co.	SERC	
2.	Bob Warren	Big Rivers Electric Corp.	SERC	
3.	Trevor Foster	Calpine Corp.	SERC	
4.	John (David) Fountain	Duke Energy Carolinas	SERC	
5.	Paul Rupard	East Kentucky Power Coop.	SERC	
6.	Charles Fink	Entergy	SERC	
7.	Marc Tunstall	Fayetteville Public Works Commission	SERC	
8.	John Clark	Georgia Power Co	SERC	

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
9.	Nathan Lovett	Georgia Transmission Corp	SERC	
10.	Danny Myers	Louisiana Generation, LLC	SERC	
11.	Ernesto Paon	Municipal Electric Authority of GA	SERC	
12.	Jay Farrington	PowerSouth Energy Coop.	SERC	
13.	Jerry Blackley	Progress Energy Carolinas	SERC	
14.	Joe Spencer	SERC Reliability Corp	SERC	
15.	Russ Evans	South Carolina Electric and Gas	SERC	
16.	Bridget Coffman	South Carolina Public Service Authority	SERC	
17.	Phillip Winston	Southern Co. Services Inc.	SERC	
18.	George Pitts	Tennessee Valley Authority	SERC	
19.	Rick Purdy	Virginia Electric and Power Co.	SERC	

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	Utilities Commission of New Smyrna Beach	FRCC	4
2.	Greg Woessner	Kissimmee Utility Authority	FRCC	1
3.	Jim Howard	Lakeland Electric	FRCC	1
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

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
54.	Group	Mallory Huggins	NERC Staff										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joel deJesus	NERC	NA - Not Applicable	NA
2.	Mike DeLaura	NERC	NA - Not Applicable	NA
3.	Bob Cummings	NERC	NA - Not Applicable	NA

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
4. David Taylor	NERC	NA - Not Applicable	NA										
5. Al McMeekin	NERC	NA - Not Applicable	NA										
6. Earl Shockley	NERC	NA - Not Applicable	NA										
55.	Individual	Terry Harbour	MidAmerican Energy Company	X									
56.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
57.	Individual	Rex Roehl	Indeck Energy Services					X					
58.	Individual	Martin Bauer	US Bureau of Reclamation					X					

1. **The SDT has made significant changes to the minimum maintenance activities and maximum allowable intervals within Tables 1a, 1b, and 1c, particularly related to station dc supply and dc control circuits. Do you agree with these changes? If not, please provide specific suggestions for improvement.**

Summary Consideration: Commenters expressed concerns with virtually all elements of posted Tables 1a, 1b, and 1c. In response to these comments, the Tables have been completely rearranged and extensively revised. The Tables now consist of one table for each of the five Protection System component types, as well as a sixth table to address monitoring and alarming requirements to support extended intervals for monitored Protection System components.

Several entities proposed extending the 3 month interval for unmonitored communication systems, and the drafting team did not adopt this suggestion because the SDT believes that three-months is necessary for these inspection-related activities related to communications systems

Organization	Yes or No	Question 1 Comment
Santee Cooper		No comment.
Xcel Energy		1. The current language is not aligned with the FAQ concerning the level of maintenance required for Dc Systems, in particular the FAQ states that with only 1 element of the Table 1b attributes in place the DC Supply can be maintained using the Table 1b activities, the table itself is clear that ALL of the elements must be present to classify the DC Supply as applicable to Table 1b. The FAQ needs to be aligned with the tables. 2. The FAQ also contains a duplicate decision tree chart for DC Supply. The FAQ contains a note on the Decision tree that reads, "Note: Physical inspection of the battery is required regardless of level of monitoring used", this statement should be placed on the table itself, and should include the word quarterly to define the inspection period.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. 1. The Tables have been rearranged and considerably revised to improve clarity. The FAQ has been modified. **2.** The FAQ has been modified.		
Pepco Holdings, Inc. - Affiliates		1. There were numerous comments submitted for Draft 1 indicating that the 3 month interval for verifying unmonitored communication systems was much too short. The SDT declined to change the interval and in their response stated: The 3 month intervals are for unmonitored equipment and are based on experience of the relaying industry represented by the SDT, the SPCTF and review of IEEE PSRC work. Relay communications using power line carrier or leased audio tone circuits are prone to channel failures and are proven to be less reliable than protective relays. Statistics on the causes of BES protective system misoperations, however, do not support this assertion. The PJM Relay Subcommittee has been tracking 230kV and above protective system misoperations on the PJM system for many years. For the six year period from 2002 to 2007, the number of protective system misoperations due to communication system problems were lower (and in many cases significantly lower) than those caused by defective relays, in every year but one. Similarly, RFC has conducted an analysis of BES protection system misoperations for 2008 and 2009, and found the number of misoperations caused by communication system problems to be in line with the number attributed to relay related problems. If unmonitored protective relays have a 6 year maximum maintenance/inspection interval, it does not seem reasonable to require the associated communication system to be inspected 24 times more frequently, particularly when relay failures are statistically more likely to cause protective system misoperations. As such, a 12 or 18 calendar month interval for inspection of unmonitored communication systems would seem to be more appropriate. FAQ II 6 B states that the concept should be that the entity verify that the communication equipment...is operable through a cursory inspection and site visit. However, unlike FSK schemes where channel integrity can easily be verified by the

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>presence of a guard signal, ON-OFF carrier schemes would require a check-back or loop-back test be initiated to verify channel integrity. If the carrier set was not equipped with this feature, verification would require personnel to be dispatched to each terminal to perform these manual checks.

2. The phrase “Verify Battery cell-to-cell connection resistance” has entered the table where it did not exist before. On some types of stationary battery units, this internal connection is inaccessible. On other types the connections are accessible, but there is no way to repair them based on a bad reading. And bad cell-to-cell connections within units will be detected by the other required tests. This requirement will cause entities to scrap perfectly good batteries just so this test can be performed, with no corresponding increase in bulk electric system reliability while taking an unnecessary risk to personnel and the environment.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. The SDT believes that the 3-month interval is proper for unmonitored communications systems.
2. This element of the table has been modified to state, “Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)” to address this comment.</td></tr>
<tr><td>Indeck Energy Services</td><td>No</td><td></td></tr>
<tr><td>GDS Associates</td><td>No</td><td>Table 1a. Protective relays

1. For microprocessor relays need guidance in how all the inputs/outputs will be checked and how is determined which one are “essential to proper functioning of the Protection System”

2. For microprocessor relays need guidance in how the acceptable measurement is physically determined.</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
Response: Thank you for comments. 1. The Standard is proscribed from describing “how.” Section 15.3 of the Supplementary Reference provides some guidance, but it is left to the entity to determine what methods best address their program. **2.** The Standard is proscribed from describing “how.” Section 15.3 of the Supplementary Reference provides some guidance, but it is left to the entity to determine what methods best address their program.		
Western Area Power Administration	No	1) Standard, Table 1a, “Control and trip circuits with electromechanical trip or aux contacts (except for microprocessor relays, UFLS or UVLS)”: Where would un-monitored control and trip circuits connected to a microprocessor relay fall, and what is the associated interval and maintenance activity? 2) Standard, Table 1a, “Control and trip circuits with electromechanical trip or aux contacts (except for microprocessor relays, UFLS or UVLS)”: Please confirm that the defined Maintenance Activity requires actual tripping of circuit breakers or interrupting devices. 3) Standard, Table 1a, “Control and trip circuits with unmonitored solid state trip or auxiliary contacts (except UFLS or UVLS)”: Please confirm that the defined Maintenance Activity requires actual tripping of circuit breakers or interrupting devices. 4) Standard, Table 1b. On page 13, for Protective Relays, please clarify the intent of “Conversion of samples to numeric values for measurement calculations by microprocessor electronics that are also performing self diagnosis and alarming.” 5) Standard, Table 1b. On page 13, for Protective Relays, please clarify the intent of “Verify correct operation of output actions that used for tripping.” Does this require functional testing of a microprocessor relay, i.e., using a relay test set to simulate a fault condition? 6) Standard, Tables 1a and 1b: Would it be possible to provide an interval credit for full parallel redundancy from relay to trip coil? 7) Table 1a (page 9) Voltage and Current Sensing Inputs to Protective Relays and

Organization	Yes or No	Question 1 Comment
		associated circuitry – This maintenance activity statement implies that signal tests to prove the voltage and current are present is all that is required. Can this be accomplished by adding a step to the Relay Maintenance Job Plan to take a snapshot of the currents and potentials (In-Service Read) with piece of test equipment? 8) Table 1b (Page 14) Control and Trip Circuitry - Level 2 Monitoring Attributes for Component is too wordy and hard to understand the meaning. Does this whole paragraph mean that the dc circuits need to be monitored and alarmed? At what level does the dc control circuits need the alarming? Can this be at the control panel dc breaker output? 9) Table 1b (Page 15) Station Dc Supply - Should this be in Table 1c because the attributes indicate that the station dc supply cells and electrolyte levels are monitored remotely. To do a fully monitored battery system would be cost prohibitive and require a tremendous amount of engineering. 10) Voltage and Current Sensing Inputs to Protective Relays and associated circuitry - This maintenance activity statement implies that signal tests to prove the voltage and current are present is all that is required. Can this be accomplished by adding a step to the Relay Maintenance Job Plan to take a snapshot of the currents and potentials (In-Service Read) with piece of test equipment? 11) Table 1a and 1b (Page 11 and 16) Associated communications system - Western has monitoring capability on all Microwave Radio and Fiber Optics communications systems with the Communications Alarm System that monitors and annunciates trouble with all communications equipment in the communications network. The protective relays that use a communications channel on these systems have alarm capability to the remote terminal units in the substation. Since these are digital channels how does an entity prove channel performance on a digital system?

Response: Thank you for your comments.

1. The Tables have been rearranged and considerably revised to improve clarity. Please see the new Table 1-5.

Organization	Yes or No	Question 1 Comment
2. The Standard requires that breakers (except for those for UFLS/UVLS) be tripped at least once during each 6 calendar year interval. See new Table 1-5. 3. The Standard requires that breakers (except for those for UFLS/UVLS) be tripped at least once during each 6 calendar year interval. See new Table 1-5. 4. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-1. 5. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-1. 6. No. The SDT believes that it is important that all parallel paths be maintained within the indicated interval, and the prescribed interval already considers the reliability benefits of parallel tripping paths. 7. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-3. It may be possible to do as suggested in some cases; a snapshot may be able to determine that voltage and current is present at the relay. However, the snapshot may not be sufficient to determine that the values are acceptable. 8. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 9. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. 10. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-3. It may be possible to do as suggested in some cases; a snapshot may be able to determine that voltage and current is present at the relay. However, the snapshot may not be sufficient to determine that the values are acceptable. **11.** Many digital communications systems or digital relays themselves use bit-error-rate or other methods to monitor and alarm on channel performance – check the design of the equipment used.		
Southern Company Transmission	No	1) Comment on Control Circuitry - Below in Figure 1 is a previous version of Table 1. It clearly shows 3 levels of monitoring for Control Circuitry. For Unmonitored schemes such as EM, SS, unmonitored MP relays, you must do a complete functional trip test every 6 years. For partially monitored schemes such as MP relays with continuous trip coil/circuit monitoring, you must do a complete functional trip test every 12 years. For fully monitored schemes where all trip paths are monitored, you do not have to trip test the scheme but you still have to operate the breaker trip coils, EM aux/lockout relays every 6

Organization	Yes or No	Question 1 Comment
		years. This is very clear and reasonable. The latest version of Table 1 is not very clear or reasonable. The previous Partially Monitored control circuit monitoring requirements were deleted and the Fully Monitored control circuit monitoring requirements were moved to Partially Monitored requirements. We are not sure why this major change in philosophy was made?? This makes all of our MP relay control schemes that continuously monitor trip coils/circuits fall into the unmonitored category and therefore requires a 6 year full functional trip test. For a scheme that monitors 99+% of the control scheme (and probably 100% of the control scheme that actually has problems) to be considered Unmonitored does not seem logical or reasonable to us. This puts these “highly monitored” schemes in the same category and requires the same maintenance requirements / intervals as EM relays with no alarms whatsoever. This also seems to contradict the intent of the following statement from the Supplementary Reference doc on page 9: Level 2 Monitoring (Partially Monitored) Table 1b This table applies to microprocessor relays and other associated Protection System components whose self-monitoring alarms are transmitted to a location (at least daily) where action can be taken for alarmed failures. The attributes of the monitoring system must meet the requirements specified in the header of the Table 1b. Given these advanced monitoring capabilities, it is known that there are specific and routine testing functions occurring within the device. Because of this ongoing monitoring hands-on action is required less often because routine testing is automated. However, there is now an additional task that must be accomplished during the hands-on process - the monitoring and alarming functions must be shown to work. Recommendation - Please consider going back to the previous table as shown below in Figure 1. It seems much clearer and reasonable. Feel free to convert the old wording to the latest wording. Figure 1 - Previous Table - Control Circuitry See Figure 1 in email documentation sent to Al McMeekin. Current Table - Control Circuitry (see pdf file) See pdf file PRC-005-2_clean_20 10June88131418.pdf in email documentation sent to Al McMeekin. 2) Comments: The comments below are grouped by component type. The following (5) comments pertain to the maintenance intervals for protective relays:

Organization	Yes or No	Question 1 Comment
		a. Is the "verify acceptable measurement of power system input values" activity listed in the protective relay 6 year interval in Table 1a the same activity as the 12-year activity for Voltage and Current Sensing Inputs in the same table? b. Please clarify the meaning of "check the relay inputs and outputs" that are specified to be checked for microprocessor relays at the following table locations: the protective relay 6 year interval in Table 1a, the protective relay 12-year interval in Table 1b. Is this referring to a check of the relay internal input recognition and output control ending at the relay case terminals, or is this referring to a check extending to the source (and target) of all inputs and outputs to the relay? The latter interpretation results in a repeat of the maintenance required for dc control circuitry. c. Are the second, third, and fourth maintenance activities in the Table 1a Protective Relay, 6-year row those activities that apply to microprocessor relays? If so, we suggest rewording these items as follows: For microprocessor relays, verify that the settings are as specified, check the relay digital inputs and outputs that are essential to proper functioning of the Protection System, and verify acceptable measurement of power system analog input values." d. Please clarify the meaning of "Verify proper functioning of the relay trip contacts" found in protective relays with trip contacts 12 year interval in Table 1c. Is this verification a check of the relay internal contact to the relay case terminals or is this meant to be a trip check functional test? This category of component does not appear in table 1a or 1b. Should it? Is this activity the same as the protective relay Table 1b maintenance activity "output actions used for tripping"? If so, please make the wording match exactly to clarify. e. Table 1c introduces the use of "Continuous" Maximum Maintenance Intervals. This is inconsistent with the Table 1a and Table 1b usage of the interval. In Tables 1a and 1b this interval is used to describe the maximum time frame within which the activities shown in "Maintenance Activities" must be completed. The table column "Maintenance Activities" has been used to identify those activities which must be performed in addition

Organization	Yes or No	Question 1 Comment
		to those accomplished by the monitoring attributes. To maintain consistency in use of the interval and activity columns of Tables 1a, 1b, and 1c, each entry that uses the “Continuous” interval should be changed to N/A and the Maintenance Activities should be changed to either “No additional activities required” or “None, due to continuous automatic verification of the status of the relays and alarming on change of settings” [example given for Table 1c, Protective Relays] 3) The following (8) comments apply to Maintenance Tables 1a, 1b, and 1c for Station DC supplies. a. In Table 1a, Station dc supply, 18 calendar month, the verify item “Float voltage of battery charger” is not listed in Table 1b. Is this requirement independent of the level of monitoring and always required? If so, should it be added in to Table 1b and 1c, Station dc supply, 18 calendar months above the “Inspect:” section? b. The 6 year interval maintenance activity for NiCad batteries in Table 1a and Table 1b should read “station battery” rather than “substation battery”. c. It is recommended to simplify the Station dc supply sections in each of the three maintenance tables by relocating the common items that do not change dependent upon the level of monitoring. Specifically, the following rows of each of the three tables have identical maintenance requirements that are independent of the level of monitoring. The tables would be significantly simplified if these “monitor level independent” requirements are moved outside of the table: I. Station dc supply; 18 calendar months; Inspect: “ II. Station dc supply (that has a s a component Valve Regulated Lead Acid batteries) III. Station dc supply (that has as a component Vented Lead Acid batteries) IV. Station dc supply (that has as a component Nickel Cadmium batteries) V. Station dc supply (battery is not used)

Organization	Yes or No	Question 1 Comment
		d. Table 1a has 18 calendar month requirements for “Station dc supply (battery is not used)”. This category is missing from Table 1b - was this intentional? e. Table 1a has 6 calendar year and 18 calendar month requirements for “Station dc supply (battery is not used)”. This category is missing from Table 1c - was this intentional? f. Please clarify the meaning of “Battery terminal connection resistance”. Does this apply only to multi-terminal batteries? Is this referring to the cables external to the battery (to the charger and load panel)? g. Table 1c contains a Type of Protection System Component not found in any of the other tables: “Station dc supply (any battery technology). Is this the same as “Station dc supply” found in Tables 1a and 1b? h. The Level 3 Monitoring Attributes for “Station dc supply (any battery technology)” are identical to the Level 2 Monitoring Attributes for “Station dc supply”. This appears to be duplicative in description with two different “maximum maintenance intervals” and “maintenance activities” listed. 4) The following (3) comments pertain to the Voltage and Current Sensing Input component type: a. Why is “signals” bolded in the Table 1a row for this component type? b. Are the Table 1a, 12 year maintenance activities for this component type a duplication of the Table 1a, Protective relay, 6 year maintenance activity for microprocessor relays (verify acceptable measurement of power system input values)? c. Why is this component type highlighted in bold in Table 1c? 5) The following (8) comments pertain to the Control and Trip Circuit component type: a. Why are microprocessor relay initiated tripping schemes excluded from the 6 year

Organization	Yes or No	Question 1 Comment
		complete functional testing? The auxiliary relay operations resulting from these initiating devices are just as likely to stick (mis-operate) as those initiated from electromechanical devices. b. We propose simplifying Table 1a for this component type by grouping the two 6 year and the two 12 year interval maintenance lines into two rather than four table rows. The 6 year interval maintenance activities for the UFLS/UVLS systems could be addressed in the table row above using a parenthetical adder to the existing text = (for UFLS/UVLS systems, the verification does not require actual tripping of circuit breakers or interrupting devices). All of the other text in the UFLS/UVLS table row matches that found two rows above. The same parenthetical adder in the first 12 year interval row for this component type would eliminate the need for the (UFLS/UVLS Systems Only) row for 12 year intervals. c. If the two rows are combined as suggested previously - this comment is irrelevant: The Table 1a 6 year interval activity for UFLS/UVLS Systems Only is missing the word “contacts” after auxiliary. d. There appears to be no difference in the 6 year interval maintenance activities for this component type in Table 1a and Table 1b. Table 1b monitoring attributes include “Monitoring and alarming of continuity of trip circuits”, but the interval between electrically operating each breaker trip coil, auxiliary relay, and lockout relay remains at 6 years. What maintenance activity advantage do the Level 1b monitoring attributes provide? e. The difference between the two DC Control Circuits in Table 1b (on page 14) is unclear. What is the difference between the “Control Circuitry (Trip Circuits)” and the “Control and trip circuitry”? We propose combing the multiple table rows for this component type into a single line item for this component type, as it takes a combination of the protective relay action, any auxiliary relay, and the circuit breaker to comprise a complete tripping system. f. We have three questions on the monitoring attributes given for this component type on

Organization	Yes or No	Question 1 Comment
		page 14: I. Does the attribute beginning "Monitoring of Protection ..." indicate a requirement to monitor every input, every output, and every connection of every Protection System Component involved in each tripping scheme? II. Does the attribute beginning "Connection paths..." related to monitoring of communication paths? III. Does the attribute beginning "Monitoring of the continuity..." require the presence of coil monitoring of any auxiliary relay whose contact is encountered when tracing a tripping path from a protective relay to a breaker? g. Are the Table 1c attributes for this component type different from the monitoring described in Table 1b beginning "Connection paths..."? h. Are there no requirements to operate any relays functionally for "Protection System control and trip circuitry" in Table 1c? The devices need to be exercised some or they will not be reliable. 6) The following (1) comment pertains to the Associated communications system component type: The Table 1b monitoring attribute for this component type (communications channel monitor and alarm) clearly should (and does) eliminate the Table 1a, 3 month interval activity (verifying the communication system is functional). The common maintenance activities found in Table 1a (6 year) and Table 1b (12 year) should be same interval - either 6 or 12.

Response: Thank you for your comments.

1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5.
2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-1 for all five of these

Organization	Yes or No	Question 1 Comment
comments. 3. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4 for all eight of these comments. 3f. Please see IEEE 450-2002 Appendix F, IEEE 1188-2005 Appendix D, and Section 6.3.2 of IEEE 1106-2005 for clarification of the meaning of “battery terminal connection resistance”. 4. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-3 for all three of these comments. 5. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5 for all eight of these comments. 6. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-2 for this comment.		
Consumers Energy Company	No	1. If multiple redundant Protection System components, with associated parallel tripping paths, are provided, Table 1a, 1b, and 1c require that each parallel path be maintained, and that the maintenance be documented. Often, these multiple schemes are provided not to meet specific reliability-related requirements, but instead to provide operating flexibility. Testing these likely will require outages, and those outages may result in decreased reliability. Further, the documentation related to maintenance of all paths will be very cumbersome, and will lead to increased compliance exposure simply by its volume. This may perversely lead to entities NOT installing the redundant schemes, resulting in decreased reliability. 2. Many of the activities described in the Tables are not, by themselves, clear. The standard should include sufficient detail such that entities are clear as to what must be done for compliance, rather that relying on supplementary documents for this information. For example, it’s not clear, in Table 1a (Station DC Supply), what is meant by, “Verify that the dc supply can perform as designed when the ac power from the grid is not present.” Similarly, it isn’t clear from the general description within the Tables that components possessing different monitoring attributes within a single scheme, may be distinguished

Organization	Yes or No	Question 1 Comment
		such that differing relevant tables can be used for the separate components. 3. In Table 1a, Station DC Supply, one of two optional activities is to “Verify that the station battery can perform as designed by evaluating the measured cell/unit internal ohmic values to station battery baseline. Battery assemblies supplied by some manufacturers have the connections made internally, making this option unavailable. Experience with ASME standards show that NERC and SDT members may be jointly and separately liable for litigation by specifying methods that either prefer or prohibit use of certain technologies. 4. Two of the four Maintenance Activities that begin with “Perform a complete functional trip ...” conclude with “... does not require actual tripping of circuit breakers or other interrupting devices. Do the other two such activities therefore require tripping of circuit breakers or other interrupting devices? 5. Performance of the minimum activities specified within Table 1a for legacy systems, particularly regarding control circuits, will require considerable disconnection and reconnection of portions of the circuits. Such activities will likely cause far more problems on restoration-to-service than they will locate and correct. We suggest that the SDT reconsider these activities with regard for this concern.

Response: Thank you for your comments.

1. The SDT believes that it is important that all parallel paths be maintained within the indicated interval, and the prescribed interval already considers the reliability benefits of parallel tripping paths.
2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5.
3. The use of the term “cell/unit” acknowledges that individual cells may not be accessible, but that assemblies of several cells (into units) may be available instead, and may be used to address this Requirement. An acceptable base-line value and follow-on tests may be acceptable for the entire station battery as a single unit.
4. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5.

Organization	Yes or No	Question 1 Comment
5. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. To the degree that performance history for the components within these systems is available, a performance-based program per Requirement R3 and Attachment A may be useful in these cases.		
JEA	No	1. R1.1 What is a Protection System component? Could the SDT provide a better understanding of what is meant by component? 2. R4: A "Failure to specify whether a component is being addressed by time-based, condition-based, or performance-based maintenance" by itself is a documentation issue and not an equipment maintenance issue. Suggest this warrants only a lower VSL, especially when one of the required components can only be time based. 3. R4: Suggest a stepped VSL for "Entity has failed to initiate resolution of maintenance-correctable issues". While we understand the importance of addressing a correctable issue, it seems like there should be some allowance for an isolated unintentional failure to address a correctable issue.
Response: Thank you for your comments. 1. A definition of "Component" has been added to the draft Standard. The SDT's intent is that this definition will be used only in PRC-005-2, and thus will remain with the Standard when approved, rather than being relocated to the Glossary of Terms. 2. This comment appears to be related to the VSL for Requirement R1, not Requirement R4 as indicated. The SDT disagrees that this is a "documentation" issue, and believes that that the related Requirement is fundamental to establishing an effective PSMP per this Standard. Also, this VSL is graded such that missing up to 5% of the required activity is indeed a Lower VSL. **3.** The VSL for Requirement R4 has been modified as suggested.		
Entergy Services	No	1. Table 1a has a "Control and trip circuits with electromechanical trip or auxiliary contacts (except for microprocessor relays, UFLS or UVLS)" component type listed, and there is a "Control and trip circuits with electromechanical trip or auxiliary [editorial comment: add 'contacts'] (UFLS/UVLS systems only)" component type listed. Suggest a "Control and trip circuits with electromechanical trip or auxiliary contacts" for a microprocessor relay

Organization	Yes or No	Question 1 Comment
		application should be addressed since it seems to be missing. 2. The term “check” has replaced “verify” for some of the maintenance activities in this draft version. What is the difference between these two terms, and shouldn’t “check” be defined if it is to be included as a PSMP activity term? 3. Assuming the term “check” replaced “verify proper functioning” in order to allow for the completion of a maintenance activity within the required interval and yet account for a maintenance correctable issue being present, suggest the other remaining activities in the tables where the term “verify proper functioning” is used, also be replaced with “check”. 4. Consider modifying the definition of “verification” to “A means of determining or checking that the component is functioning properly or maintenance correctable issues are identified”, eliminate use of the term “verify proper functioning” (which seems to be redundant by PRC-005-2 standard definition), and simply use the term “verify”.
Response: Thank you for your comments. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 2. “Check” is not an element of the PSMP definition. This term has been replaced throughout the tables with whatever term of the definition is relevant. 3. “Check” is not an element of the PSMP definition. This term has been replaced throughout the tables with whatever term of the definition is relevant. **4.** The terms within the PSMP definition have been revised to reflect the action (“verify” rather than “verification,” for example). The SDT believes that the use of the term “verify” within the modified tables and the definition of this component in the PSMP definition is appropriate and correct.		
MEAG Power	No	1. The descriptions for the "type of protection system components" do not appear to be consistent between Tables, 1a, 1b and 1c.

Organization	Yes or No	Question 1 Comment
		2. The maximum maintenance interval for a lead-acid vented battery is listed at 6 calendar years for performing a capacity test. This type of test has been proven to reduce battery life and an interval of 10 to 12 years would be better. 3. The maximum maintenance interval for "Station DC supply" was set at 3 months. This is too short of a period and 6 months would be better. 4. The control and trip circuits associated with UVLS and UFLS do not require tripping of the breakers but all other protection systems require tripping of the breakers, this appears to be inconsistent? 5. Digital relays have electromagnetic output relays. Do they fall into the electromechanical trip or solid state trip? 6. Need for clarification: The standard indicates that only voltage and current signals need to be verified. Does this mean that voltage and current transformers do not need to be tested by applying a primary signal and verifying the secondary output?

Response: Thank you for your comment.

1. The Tables have been rearranged and considerably revised to improve clarity and consistency. Please see new Table 1-5.
2. The SDT disagrees, and believes that a capacity test at 6-year levels is appropiate. A properly maintained battery, according to various credible references (from IEEE, EEI, EPRI, various manufacturers, etc.), can easily handle multiple deep discharges over its expected life.
3. The activity related to this interval is to verify various basic operating parameters. The SDT believes that extension of verification of these parameters beyond the interval within the Standard is inappropriate.
4. This is an intentional difference between UFLS/UVLS and the remainder of the Protection Systems addressed within the Standard, because of the distributed nature of UFLS/UVLS and because these devices are usually tripping distribution system elements.
5. These devices fall under “electromechanical output contacts.” The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-1.

Organization	Yes or No	Question 1 Comment
6. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-3.		
Ameren	No	Ameren does agree that draft 2 is a considerable improvement from draft 1 of PRC-005-2; however the following still need to be addressed. 1) Use “Control circuitry” to be consistent with the proposed definition. If ‘and trip’ was included so that users would know this is a trip circuit, then the definition should use ‘Trip circuitry’ instead of ‘Control circuitry’. It is important to use consistent terminology throughout the definition and the standard. 2) Please add row numbers in each of Tables 1a, 1b, and 1c, and arrange so that row 1 in each table corresponds, etc. (or state which rows correspond to each other.) This would help clarify movement from table to table. The number of sub clauses, nuances, and varied Type of Component descriptors among rows in the same table as well as from table-to-table can be overwhelming. This would help keep Regional Entities and System Owners from making errors. 3) Please clarify that the instrument transformer itself is excluded. The standard indicates that only voltage and current signals need to be verified. The FAQ seems to cover this, but see our comments on your question 6. 4) Clarifications need to be made on testing requirements on trip contacts relative to microprocessor vs. EM relays. Digital relays have electromagnetic output relays. Do they fall into the electromechanical trip or solid state trip? 5) There appears to be an inconsistency in the use of “check” vs. “verify” in the tables. Consider modifying the definition of “verification” to “A means of determining or checking that the component is functioning properly or that the maintenance correctable issues are identified”, eliminate use of the term “verify proper functioning” (which seems to be redundant by PRC-005-2 standard definition), and simply use the term “verify”. 6) Alternately if the term “check” replaced “verify proper functioning” in order to allow for the completion of a maintenance activity within the required interval and yet account for an

Organization	Yes or No	Question 1 Comment
		outstanding maintenance correctable issue being present, suggest the other remaining activities in the tables where the term “verify proper functioning” is used, also be replaced with “check”. 7) If there is an intentional difference between “verify” and “check”, shouldn’t “check” be defined if it is to be included as a PSMP activity term? 8) Functional trip testing will require extensive analysis and could involve an extensive testing evolution to ensure the correct circuit is tested without unexpected trip of other components, particularly for generator protection systems and some transmission configurations. The complexity of the system and the test would be conducive to an error that resulted in excessive tripping, thus affecting the reliability of the BES. It would seem that the potential for an adverse affect from this test would be greater than the benefit gained of testing the circuit. In addition, scheduling outages to perform the functional trip testing in conjunction with other outages required to perform maintenance and other construction activities will be difficult due to the large number of outage requirements for the functional testing. This will challenge the BES more often and thus reduce reliability. For these reasons functional trip testing is too frequent, and should be extended to twelve years. 9) In battery maintenance table, we suggest that “cell/unit” be changed to “cell or unit.” Suggest substituting “unit-to-unit” wherever “cell-to-cell” is used in the table now. Many batteries are packaged such that the individual cells are not accessible. 10) IEEE battery maintenance standards call for quarterly inspections. These are targets, though, not maximums. An entity wishing to avoid non-compliance for an interval that might extend past three calendar months due to storms and outages must set a target interval of two months thereby increasing the number of inspections each year by half again. This is unnecessarily frequent. We suggest changing the maximum interval for battery inspections to 4 calendar months. For consistency, we also suggest that all intervals expressed as 3 calendar months be changed to 4 calendar months. 11) Replace “State of charge of the individual battery cells/units” with “Voltage of the

Organization	Yes or No	Question 1 Comment
		individual battery cells or units”. 12) The maximum maintenance interval for a lead-acid vented battery is listed at 6 calendar years for performing a capacity test. This type of test has been proven to reduce battery life and an interval of 10 to 12 years would be better. 13) The level 2 table regarding Protection Station dc supply states that level 1 maintenance activities are to be used, but then goes on to give a list of Maintenance Activities that don’t match those in level 1. Which activities shall we use? Same situation for Station DC Supply (battery is not used) where the 18 month interval is missing. 14) Also, Table 1B, in the second to last row, should be referring to UFLS rather than SPS.

Response: Thank you for your comments.

1. The Tables have been rearranged and considerably revised to improve clarity and consistency. Please see new Table 1-5.
2. The Tables have been rearranged and considerably revised to improve clarity and consistency. Please see new Table 1-5.
3. The definition has been modified to clarify that instrument transformers ARE part of the Protection System, and the maintenance activities in the new Table 1-3 specify WHAT must be done regarding this component type. The FAQ (II.3.A) is correct on this subject.
4. The Tables have been rearranged and considerably revised to improve clarity. These devices fall under “electromechanical output contacts.” The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-1.
5. “Check” is not an element of the PSMP definition. This term has been replaced throughout the Tables with whatever term of the definition is relevant. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5.
6. “Check” is not an element of the PSMP definition. This term has been replaced throughout the Tables with whatever term of the definition is relevant. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5.
7. “Check” is not an element of the PSMP definition. This term has been replaced throughout the Tables with whatever term of the definition is relevant.
8. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">9. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. This element of the table has been modified to state, “Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)” to address this comment.
10. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. The Requirement remains as “3 Calendar Months” and the SDT is not prescribing or suggesting what measures an entity may take within their program to assure compliance.
11. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. Verification of voltage of individual cells, etc., is one method; there are other ways.
12. The SDT disagrees, and believes that a capacity test at 6-year intervals is appropiate for Vented Lead Acid and Ni-Cad batteries. A properly maintained battery, according to various credible references (from IEEE, EEI, EPRI, various manufacturers, etc.), can easily handle multiple deep discharges over its expected life.
13. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4.
14. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-5.</td></tr>
<tr><td>American Transmission Company</td><td>No</td><td>ATC feels additional changes are needed.
1. The functional testing requirement should be altered or removed as it increases the amount of hands-on involvement and the opportunity for human error related outages to occur, thereby introducing more opportunities to decrease system reliability. As noted on p. 8 in the supplementary reference document, “Experience has shown that keeping human hands away from equipment known to be working correctly enhances reliability.” By removing circuits from service on the proposed timelines for functional testing, the chance for human error is greater than a mis-operation from faulty wiring. Alternatively, entities may choose to schedule more planned outages to conduct their functional testing in order to limit the risk of unplanned outages resulting from human error. Under this scenario, more elements will be scheduled out of service on a regular basis, thereby reducing transmission system availability and weakening the system making it more challenging to withstand each subsequent contingency (N-1). Thus testing an in-tact</td></tr>
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Organization	Yes or No	Question 1 Comment
		system is more desirable than taking it out of service for testing. 2. While the SDT has included language in the draft standard to use fault analysis to complete maintenance obligations, in practicality, this option does not offer any relief to taking outages to perform functional tests. Nearly all BES circuit breakers are equipped with dual trip coils. Identifying which trip coil operated for a fault only covers the one trip coil. Functional tests would still be needed on the other. The likelihood of having multiple trips on a given line in the course of several years is very low. Given it can take a year to schedule some outages, planning maintenance with random faults is unpractical and will create unacceptable risk to compliance violations. A better approach is to use the basis in schedule A, but extend this to cover the entire protection schemes. The document should establish target goals for mis-operation rates (dependability and security). This would allow the utilities to develop cost effective programs to increase reliability. The utilities would have incentives to replace poorly performing communications systems; they would be able to quantify the value of upgrading relay systems.
Response: Thank you for your comments. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. **2.** Operational results, if desired by an entity, MAY be used to meet maintenance requirements to the degree that they verify, etc., the relevant performance. Whether their use is effective for a specific entity is left to the entity to determine. “Maintenance correctable issues,” which may result in part from misoperations, are a part of using Attachment A to develop a Performance Based PSMP.		
Corporate Compliance	No	Battery visuals should be changed from 3 months to 6 months. Electrolyte levels of today’s lead-calcium batteries are relatively stable for a 6 month period compared to lead-antimony batteries used in the past.
Response: Thank you for your comments. The activity related to this interval is to verify various basic operating parameters. The SDT believes that extension of verification of these parameters beyond the interval within the Standard is inappropriate.		

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	1. Clarification is needed for “to a location where action can be taken”. Some examples in the FAQ will help in this clarification. 2. What type of documentation is required to show compliance that maintenance correctable issue has been reported? 3. Clarify the removal of requirement (see redline version, third row of Table 1a) for testing of unmonitored breaker trip coils. Is it the intention of the SDT to remove a requirement that would drive the industry to install TC monitors on breakers to improve reliability? 4. UFLS/UVLS DC control and trip circuits (Rows 5 and 6 of Table 1a) - Due to the distributed nature of this program, random failures to trip are not impactive to the overall operation of the UFLS protection. There should be no requirement to check the DC portion of these protections any more often than the DC circuit checks associated with that LV breaker. Since it is clear the requirement does not include the need to trip the breakers why the need to check the trip paths? Deletion of this requirement leaves the requirement to check only the relays and relay trip outputs from the protections every 6 years (or as often as the protective relay component type). Should the maintenance activities for “UVLS and UFLS relays that comprise a protection scheme distributed over the power system” not be the same as “Protective Relays”? V and I sensing to relays have a 12 year Maximum Maintenance Interval listed. It is good work practice to have this activity done the same time as maintenance activities associated with relay maintenance. 5. What is the basis for the various Maximum Maintenance Intervals listed in Table 1a? 6. From page 12 of the redline version, for "Station dc Supply (used only for UFLS and UVLS)", is the requirement applicable to distribution substations only? 7. For “Control and trip circuits with unmonitored solid-state trip or auxiliary contacts (UFLS/UVLS Systems only)” under Maintenance Activities - the word “complete: may be removed as it requires to actually trip the breakers. The sentence that tripping of the circuit breakers is not required contradicts with the word “complete”. More specifics are

Organization	Yes or No	Question 1 Comment
		required to spell out the adequate testing e.g. up to the lockout with the trip paths isolated etc. See Page 12 of the redline version. 8. For “Station dc Supply” having 18 calendar months as the Maximum Maintenance Interval, a battery has a 20 year life. IEEE standard PM is on a quarterly basis. What is the basis of the 18 calendar month interval? See page 12 of the redline version. 9. For “Associated communications systems” with a Maximum Maintenance Interval of 6 Calendar years, why is this required? The text "Verify proper functioning of communications equipment inputs and outputs that are essential to proper functioning of the Protection System. Verify the signals to/from the associated protective relay(s)" seems sufficient to ensure reliability. See page 15 of the redline version. 10. For “Relay sensing for Centralized UFLS or UVLS systems UVLS and UFLS relays that comprise a protection scheme distributed over the power system” under maintenance activities, clarify “overlapping segments”. What is the specified interval? Is actual breaker tripping required? See page 15 of the redline version. 11. On the row for Associated communications systems in Table 1c, in the Level 3 Monitoring Attributes for Component column, suggest a change in wording to: Evaluating the performance and quality of the channel as well as the performance of any interface to connected protective relays and alarming if the channel/protective relay connections do not meet performance criteria. 12. In Table 1c it is required to report the detected maintenance correctable issues within 1 hour or less to a location where action can be taken to initiate resolution of that issue. Even for a fully monitored protection system component it can be difficult to report the action in 1 hour. A 24 hour period for both Level 2 and Level 3 reporting of maintenance correctable issues is recommended.

Response: Thank you for your comments.

1. This is addressed in the Supplementary Reference document as posted with this draft (Section 8.1 and Section 13), and within the

Organization	Yes or No	Question 1 Comment
FAQ as posted with this draft Standard (V.3.D). 2. Specific effective forms of documentation are left to the entity to determine, but the SDT believes that this could include, among other things, work orders addressing the maintenance correctable issue. 3. The Tables have been rearranged and considerably revised to simplify and improve clarity. Please see new Table 1-5. Specifically to your comment, the SDT initially specified inspection of trip-coil monitoring functions at intervals of 3 months, with tripping otherwise requried annually. This has been revised to simply require tripping at 6-calendar-month intervals. 4. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 5. Please see Supplementary Reference, Section 8.3. 6. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. Specifically for this item, this applies to whatever interrupting device is being tripped by the UFLS/UVLS. To the degree that the same interrupting devices are tripped by other Protection System components, the relevant Requirements apply. 7. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 8. This interval is based on EPRI and other industry documents referencing these specific activities. 9. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-3. 10. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-1. 11. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-3. **12.** The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 2. This requirement is now uniformly 24 hours as suggested within the comment.		
SERC Protection and Control Sub-committee (PCS)	No	1. Clarifications need to be made on testing requirements on trip contacts relative to microprocessor vs. EM relays. There appears to be an inconsistency in the use of “check” vs. “verify” in the tables. 2. Also, Table 1B, in the second to last row, should be referring to UFLS rather than SPS. 3. Also, note that M2 incorrectly excludes distribution provider.

Organization	Yes or No	Question 1 Comment
		4. In battery maintenance table, we suggest that "cell/unit" be changed to "cell or unit."
Response: Thank you for your comments. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 3. Measure M2 has been corrected as suggested. **4.** The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4.		
BGE	No	Comment 1.1: In its decision to use "calendar years" with the maintenance intervals prescribed for most components the SDT has provided a framework that is consistent with a well-run PSMP but with enough flexibility to be practical. However BGE believes the application of this approach to short maintenance intervals, like three months for some battery maintenance will risk numerous violations due to practical scheduling constraints that are not a realistic threat to reliability. As the requirements are presently defined the inherent flexibility for battery maintenance that is nominally done on three month intervals may be as long as 1/3 of the interval or as short as one day (Our interpretation: Maintenance last done on January 1 is next due on April 1 and can be done no later than April 30. Maintenance done on Jan 31 is next due on April 30 and is overdue if done on May 1). The only practical solution is to increase the frequency so that the average intervals are significantly shorter than the nominal requirement.BGE recommends an alternate formulation for intervals if the nominal interval is less than one year. Some possible alternatives (assuming a three month nominal interval): Once per calendar quarter no later than the end of the quarter no earlier than one month before it. Four times per year, no more than 120 days apart no less than 60. Comment 1.2: On page 11, Row-3/Column-1 of Table-1a includes the following entry for functional trip testing:"Control and trip circuits with electromechanical trip or auxiliary contacts (except for microprocessor relays, UFLS or UVLS)". It is not clear why

Organization	Yes or No	Question 1 Comment
		electromechanical trip contacts in microprocessor relays are excluded. Comment 1.3: On page 12, Row-3/Column-3 of Table-1a includes the following Verification Task for Station DC Supplies: "Verify Battery cell-to-cell connection resistance". Multiple cell units do not provide the ability to measure cell-cell resistance.
Response: Thank you for your comments. 1. The intervals remain as prescribed within the Standard and are designed to be effective, clear, and consistently monitored for compliance; the SDT is not prescribing or suggesting what measures an entity may take within their program to assure compliance. 2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. **3.** This element of the table has been modified to state, “Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)” to address this comment.		
Constellation Power Generation	No	1. Constellation Power Generation (CPG) does not agree with the maximum maintenance interval for associated communication systems and station dc supply that has as a component any type of battery, which is 3 months. If the intent of the drafting team was to make this test quarterly (as recommended in IEEE-450), than the maximum interval should be 4 months. As written, for a registered entity to ensure they complete this test in an interval less than 3 months, they will most likely complete this test every 2 months. This causes two additional and unwarranted tests every year. CPG recommends an alternate formulation for intervals if the nominal interval is less than one year. Some possible alternatives (assuming a three month nominal interval): Once per calendar quarter no later than the end of the quarter no earlier than one month before it. Four times per year, no more than 120 days apart no less than 60. 2. CPG does not agree with differentiating between the different battery types. A suggestion would be to take the maximum maintenance interval for all the battery types, which is 6 years, and apply them across all types of batteries, eliminating the need to

Organization	Yes or No	Question 1 Comment
		differentiate between them. Furthermore, multiple cell units do not provide the ability to measure cell-cell resistance, and so that requirement should be removed. 3. CPG is not clear why electromechanical trip contacts in microprocessor relays are excluded in Table 1a.
Response: Thank you for your comments. 1. The intervals remain as prescribed within the Standard and are designed to be effective, clear, and consistently monitored for compliance; the SDT is not prescribing or suggesting what measures an entity may take within their program to assure compliance. 2. The appropriate maintenance activities and intervals differ considerably for various battery types. This element of the table has been modified to state, "Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)" to address this comment. **3.** The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-1.		
Exelon	No	Exelon does not completely agree with the minimum maintenance activities and maximum allowable intervals as suggested by SDT. Comments on minimum maintenance activities: 1. Reference Table 1a (Page 11) of Standard PRC-005-2: With regard to the maintenance activity: "Verify that the station battery can perform as designed by conducting a performance ......". The standard should clearly define what is meant by "perform as designed" to eliminate ambiguity in future interpretations. 2. Also, Table 1a Station dc supply (that has as a component Vented Regulated Lead-Acid batteries) discusses "modified performance capacity test of the entire battery bank". This needs additional clarification or should be reworded because modified test includes both the performance test (which is the capacity test) and the service test. Should be reworded to be "modified performance test". 3. Comments on maximum allowable intervals: Nuclear generating stations have refueling outage schedule windows of approximately

Organization	Yes or No	Question 1 Comment
		18 months or 24 months (based on reactor type). If for some reason the schedule window shifts by even a few days, an issue of potential non-compliance could occur for scheduled outage-required tasks. The possibility exists that a nuclear generator may be faced with a potential forced maintenance outage in order to maintain compliance with the proposed standard. For the requirements with a maximum allowable interval that vary from months to years (including 18 Months surveillance activities), the SDT should consider an allowance for NRC-licensed generating units to default to existing Operating License Technical Specification Surveillance Requirements if there is a maintenance interval that would force shutting down a unit prematurely or face non-compliance with a PRC-005 required interval. Therefore, Tables 1a, 1b & 1c should include an allowance for any equipment specifically controlled within each licensee's plant specific Technical Specifications to implement existing Operating License requirements if such a conflict were to occur. Please see additional comments under Q7.
Response: Thank you for your comments. 1. This concern is addressed within IEEE standards (specifically IEEE 450, IEEE 1188, and IEEE 1106) by their description and definition of a "performance test" as further established within this requirement. The SDT believes that entities involved in battery maintenance will be familiar with these IEEE standards. 2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. **3.** The intervals and activities specified are believed by the SDT to be technically effective, in a fashion that may be consistently monitored for compliance. It is left to the the entity to determine how to align these requirements with requirements of other regulations and with operational concerns. Entities should be able to complete the activities with 18-month or shorter intervals without outages. See the SDT responses to your comments in Question 7.		
Black Hills Power	No	1. For Protective Relays, Table 1a Maintenance Activities has no requirement for verifying output contacts on non-microprocessor based relays. The actual contacts used for tripping should be verified by this activity.

Organization	Yes or No	Question 1 Comment
		2. For Protective Relays, Table 1b Maintenance Activities states "Verify correct operation of output actions that are used for tripping". This requirement is vague and needs to define whether all protection logic or conditions that would initiate a relay trip output are required to be simulated and tested to the relay tripping output contact. 3. For Voltage and Current Sensing Inputs to Protective Relays and associated circuitry, Table 1a references "current and voltage signals" and Table 1b references "current and voltage circuit signals". Need consistency or definitions to meet this requirement. 4. For Control and trip circuits with electromechanical trip or auxiliary (UFLS/UVLS Systems Only), Table 1a states "except that verification does not require actual tripping of circuit breakers or interrupting devices." This exception to the requirement seems to defeat the whole purpose of the standard and leaves a huge gap open to interpretation and conflict. -For Control and trip circuits with unmonitored solid-state trip or auxiliary contacts (UFLS/UVLS Systems Only), Table 1a states "except that verification does not require actual tripping of circuit breakers or interrupting devices." This exception to the requirement seems to defeat the whole purpose of the standard and leaves a huge gap open to interpretation and conflict. 5. For Station dc supply, Table 1a requirement includes "Inspect: The condition of non-battery-based dc supply." This is redundant with the requirements of the section Station dc supply (battery is not used) and should be removed from this section. 6. For Voltage and Current Sensing Inputs to Protective Relays and associated circuitry, a maximum interval of verification of 12 years seems to contradict the intent of the rest of the Maintenance standard which dictates 6 years on all of the other components. The requirement for these components should fall in line with the rest of the standard.

Response: Thank you for your comments.

1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-1.
2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-1. "Verify" is defined within

Organization	Yes or No	Question 1 Comment
the PSMP defintion. 3. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-3. 4. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. This is an intentional difference between UFLS/UVLS and the remainder of the Protection Systems addressed within the Standard, because of the distributed nature of UFLS/UVLS and because these devices are usually tripping distribution system elements. 5. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. **6.** The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-3. These devices are not typically subject to in-service degradation to the degree that those with 6-year intervals are. Entities have the latitude to perform maintenance more frequently than specified if they feel that such maintenance is needed.		
Duke Energy	No	General comment - the draft changes the word “verify” to “check” in several places; should use consistent phrasing throughout the standard. With regards to Table 1a, we have the following comments: 1. Control and trip circuits with electromechanical trip or auxiliary contacts (except for microprocessor relays. UVLS or UFLS) - We believe that while there may be value in a 6 calendar year cycle, this will be difficult to accomplish, since you either have to get outages scheduled or block protection, which risks reliability. Since this is essentially a re-commissioning check, the cycle should be 12 calendar years. Also 6 years appears to be in conflict with the system protection standard. 2. Control and trip circuits with unmonitored solid-state trip or auxiliary contacts (except for UVLS or UFLS) - agree with 12 calendar years as consistent with electromechanical above. 3. Control and trip circuits with electromechanical trip or auxiliary (UVLS or UFLS Systems Only) - 6 year cycle should be changed to 12 calendar years (see comment above on non-UVLS/UFLS). 4. Control and trip circuits with unmonitored solid-state trip or auxiliary contacts (UVLS or

Organization	Yes or No	Question 1 Comment
		UFLS Systems Only) - agree with change to 12 calendar years. 5. Station dc Supply (used only for UVLS or UFLS) - Strike the word "Station". We don't differentiate between dc supply used for UFLS and other protection. 6. Station dc supply - Change 18 calendar months to 24 months, since this testing requires generator outages. Nuclear plant fuel cycles can be longer than 18 months. 7. Associated communications systems - More clarity is needed regarding what is to be included in the definition of "Associated".
Response: Thank you for your comments. "Check" is not an element of the PSMP definition. The term has been replaced throughout the tables with whatever term of the definition is relevant. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. The circuit itself is 12 years, but interval for the electromechanical devices such as aux or lockout relays remains at 6 years, as these devices contain "moving parts" which must be periodically exercised to remain reliable. 2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 3. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 4. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 5. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. 6. The SDT believes the specified intervals and activities are technically effective, and in a fashion that may be consistently monitored for compliance. The entity must determine how to best align these requirements with requirements of other regulations and with operational concerns. Entities should be able to complete the activities with 18-month or shorter intervals without outages. **7.** This portion of the definition of Protection System has been modified for clarity. Also, the Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-3.		
American Electric Power	No	1. In Table 1a for the component "Station dc Supply (used only for UVLS and UFLS)", the

Organization	Yes or No	Question 1 Comment
		interval prescribed is "(when the associated UVLS or UFLS system is maintained)" and the activity is to "verify the proper voltage of the dc supply". The description of the interval "(when the associated UVLS or UFLS system is maintained)" needs to be changed. Relay personnel do not generally take battery readings. The interval should read "according to the maximum maintenance interval in table 1a for the various types of UFLS or UVLS relays". The testing does not need to be in conjunction with the relay testing, it is only the test interval that is important, although relay operation during relay testing is a good indicator of sufficient voltage of the battery. 2. The monitoring and/or maintenance activities listed for batteries are not appropriate in Tables 1b and 1c. There are no commercial battery monitors that monitor and alarm for electrolyte level of all cells. Why not move the electrolyte level to the 18 month inspection and actually open the possibility of condition monitoring to commercially available devices? Or give an option to do the electrolyte check at other time intervals (perhaps 12 months) by visual electrolyte inspection and still allow the monitoring of other functions on the listed 6 year schedule using condition monitoring. It makes no sense to prescribe an unattainable condition monitoring solution. The way that the tables are written, there is no advantage to use the charger alarms since battery maintenance requirements are not reduced in any way.
Response: Thank you for your comments. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. **2.** The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4.		
Great River Energy	No	1. In Table 1a section-Station DC Supply - 18 calendar months, under Maintenance Activities column, suggest changing under Verify: Battery terminal connection resistance To: Entire battery bank terminal connection resistance (This could have been interpreted as individual batteries) And change: Battery cell-to-cell connection resistance To: Battery cell-to-cell connection resistance, where an external mechanical connection is available.

Organization	Yes or No	Question 1 Comment
		2. In Table 1a-Station dc supply (that has a component Valve Regulated Lead-Acid batteries) suggest changing Max Maintenance Interval=3 Calendar Years or 3 Calendar Months to 4 Calendar Years or 12 Calendar Months. Our concern is that the insurance companies may push NERC maintenance intervals on all battery banks not associated with the BES. 3. Table 1a-Station dc supply (that has as a component Lead-Acid batteries) Max Maintenance Interval=6 Calendar Years suggest changing to 10 Calendar Years. Reason: performance tests may degrade the battery. 4. Table 1a-Station dc supply (that has as a component Nickel-Cadmium batteries) Max Maintenance Interval=6 Calendar Years suggest changing to 10 Calendar Years. Reason: performance tests may degrade the battery. 5. Table 1b -Level 2 Monitoring Attributes for Component in the row labeled (Control and trip circuitry) we suggest the following change: If a trip circuit comprises multiple paths, at least one of those paths is monitored. Alarming for loss of continuity or dc supply for trip circuits is reported to a location where action can be taken. 6. While all tripping circuits are not completely monitored, the trip coils and the outdoor cable runs are completely monitored. The only portion that would not be monitored is a portion of inter and intra-panel wiring having no moving parts located in a control house. Our company has extremely low failure rate of panel wiring and terminal lugging. I don't think that there is provision for moving control and trip circuitry to performance based maintenance? This control circuitry should be maintained less frequent than un-monitored trip circuits (6 years).

Response: Thank you for your comments.

1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. This element of the Table has been modified to state, "Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)" to address this comment.

Organization	Yes or No	Question 1 Comment
2. NERC Standards are limited to facilities and equipment related to the BES. How the Standard may be otherwise used is outside the scope of NERC Standards. 3. The SDT disagrees, and believes that a performance test at 6-year intervals is appropiate for Ni-Cad batteries. A properly maintained battery, according to various credible references (from IEEE, EEI, EPRI, various manufacturers, etc.), can easily handle multiple deep discharges over its expected life. 4. The SDT disagrees, and believes that a performance test at 6-year intervals is appropiate for Vented Lead Acid and Ni-Cad batteries. A properly maintained battery, according to various credible references (from IEEE, EEI, EPRI, various manufacturers, etc.), can easily handle multiple deep discharges over its expected life. 5. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. **6.** The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. Nothing in the draft Standard (including Attachment A) precludes an entity from using performance-based maintenance for dc control circuits.		
Long Island Power Authority	No	1. In Table 1c it is required to report the detected maintenance correctable issues within 1 hour or less to a location where action can be taken to initiate resolution of that issue. Even for a fully monitored protection system component it can be difficult to report the action in 1 hour. LIPA recommends a 24 hour period for both Level 2 and Level 3 reporting of maintenance correctable issues. The time identified is report time and not response time to correct issue. 2. LIPA seeks clarification on “to a location where action can be taken”. Some examples in the FAQ will help in this clarification. 3. What type of documentation is required to show compliance that maintenance correctable issues have been reported? 4. What is the basis of the various Maximum Maintenance Intervals tabulated in Table 1a-Time based maintenance?
Response: Thank you for your comments.		

Organization	Yes or No	Question 1 Comment
1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5 and Table 2. These Tables reflect your proposed change. 2. This is addressed in the Supplementary Reference document as posted with this draft (Section 8.1 and Section 13), and within the FAQ as posted with this draft Standard (V.3.D). 3. Specific effective forms of documentation are left to the entity to determine, but the SDT believes that this could include, among other things, work orders addressing the maintenance correctable issue. **4.** Please see Section 8.3 of the Supplementary Reference document.		
Northeast Utilities	No	1. In Table 1c it is required to report the detected maintenance correctable issues within 1 hour or less to a location where action can be taken to initiate resolution of that issue. Even for a fully monitored protection system component it can be difficult to report the action in 1 hour. Recommend a 24 hour period for both Level 2 and Level 3 reporting of maintenance correctable issues. 2. Additionally, please clarify meaning of “to a location where action can be taken”.
Response: Thank you for your comments. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5 and Table 2. These tables reflect your proposed change. **2.** This is addressed in the Supplementary Reference document as posted with this draft (Section 13), and within the FAQ as posted with this draft Standard (V.3.D).		
MidAmerican Energy Company	No	1. In the tables trip circuit has been replaced by “control and trip circuit”. From the context of the standard and the reference and frequently asked question documents it is clear that the requirement is to test the trip circuit only. Adding the word “control’ introduces ambiguity and the potential to imply the closing circuit of the interrupting device also requires testing under the standard. The word “control” should be removed. On this same subject the nomenclature in Table 1b for type of protection system component is

Organization	Yes or No	Question 1 Comment
		not consistent with Table 1a.In Table 1b in the Level 2 Monitoring Attributes for Component column for Relay sensing for centralized UFLS or UVLS systems there is a reference to SPS. This reference should likely be to UFLS/UVLS. 2. In Table 1a functional testing of associated communications systems is included with a maximum maintenance interval of 3 calendar months. Testing of this equipment at that frequency is not believed to be necessary. It is suggested that the interval be changed to 12 calendar months. 3. For control and trip circuit maintenance the requirement includes “a complete functional trip test”. In order to accomplish this type of testing given current design of lock-out relay and interrupting device trip circuitry multiple breakers and line terminal outages would be required simultaneously. In addition complete functional testing has the potential to result in unintentional tripping of equipment that could cause equipment damage and customer outages. Segmentation of trip circuits by lifting wires has the potential for incorrect restoration following testing. This type of testing has the potential to degrade system reliability as multiple entities schedule this work. An alternate to complete functional testing that does not potentially degrade system reliability should be substituted.
Response: Thank you for your comments. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 2. The SDT believes that the 3-month interval is proper for unmonitored communications systems. **3.** The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. The interval for maintenance of electromechanical devices such as aux or lockout relays remains at 6 years, as these devices contain “moving parts” which must be periodically exercised to remain reliable.		
Nebraska Public Power District	No	1. It would be very helpful in Table 1a, 1b, and 1c to reference the FAQ or Supplemental Reference by page number and section number for the corresponding

Organization	Yes or No	Question 1 Comment
		Maintenance Activity statements. 2. Table 1a, Control and Trip Circuits with electromechanical trip or auxiliary contact - how is the control and trip circuit functional trip test performed without affecting the BES or without tripping more than just the breaker (trip coil)? What is the basis for an actual trip of the breaker that will affect the BES? Functional trip testing will require extensive analysis and could involve an extensive testing evolution to ensure the correct circuit is tested without unexpected trip of other components, particularly for generator protection systems. The complexity of the system and the test would be conducive to an error that resulted in excessive tripping, thus affecting the reliability of the BES. It would seem that the potential for an adverse affect from this test would be greater than the benefit gained of testing the circuit. In addition, scheduling outages to perform the functional trip testing in conjunction with other outages required to perform maintenance and other construction activities will be difficult due to the large number of outage requirements for the functional testing. This will challenge the BES more often and thus reduce reliability. 3. 2. Table 1a, Control and Trip circuits with electromechanical trip or auxiliary contacts - What is the differentiation between control and trip circuits? The FAQ appears to use the term interchangeably. 4. Table 1a, associated communication systems - What is the basis for checking that the associated communication equipment is functioning every 3 calendar months for unmonitored components? NPPDs experience indicates that a check every 6 months is sufficient.

Response: Thank you for your comments.

1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5. Doing as you suggest would make the supporting information with the FAQ and Suppementary Reference part of the Standard, and this would add extensive and unnecessary prescription to the Standard.

2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. These devices contain

Organization	Yes or No	Question 1 Comment
"moving parts" which must be periodically exercised to remain reliable. 3. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. The FAQ has been modified. 4. The SDT believes that the 3-month interval is proper for unmonitored communications systems.		
Y-W Electric Association, Inc.	No	Many of the changes to the proposed standard are reasonable and improve the clarity of the standard and its requirements. However, Y-WEA concurs with Central Lincoln and FMPA on their comments regarding the testing of battery cell-to-cell connection resistance. Many types of stationary batteries are actually blocks of two or more cells that are internally connected. This requirement would necessitate either some sort of feasibility exception process (which, as shown by the TFE process with the CIP standards can be very difficult, cumbersome, and time-consuming to develop and administer) or replacement of the batteries in question, which would pose enormous burdens on small entities that must comply with this standard. The language in this requirement should be changed from "cell-to-cell" to "unit-to-unit" in order to avoid these issues.
Response: Thank you for your comments. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. This element of the table has been modified to state, "Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)" to address this comment.		
Progress Energy Carolinas	No	1. The modified definition of "Protection System" (page 2 of the clean version of PRC-005-2) uses the terminology "control circuitry associated with protective functions" whereas Table 1a rows 3-6, Table 1b Rows 3 and 5, and Table 1c Row 4 uses the terminology "control and trip circuits." This is a conflict. "Control" implies that the standard applies to closing/reclosing circuits as well. We do not believe that is the intent. 2. Row 7 of Table 1a (page 10 of the clean version of PRC-005-2) indicates that proper

Organization	Yes or No	Question 1 Comment
		voltage of the station dc supply must be verified when the associated UVLS or UFLS maintenance is performed. It is not clear whether this requirement is over and above the quarterly and 18-month battery maintenance listed elsewhere in the table or is it the only battery maintenance required for UVLS and UFLS systems? If the intent is to check the station dc supply only when UVLS and UFLS maintenance is performed, the other rows addressing station dc should be revised to exclude UVLS and UFLS. 3. Row 4 of Table 1b (page 14 of the clean version of PRC-005-2) indicates that remote alarms must be verified every twelve calendar years for control circuitry (trip circuits) (except UFLS/UVLS) provided “Monitoring of Protection System component inputs, outputs, and connections” exists. Clarification should be made to indicate how to monitor inputs. For example, a breaker auxiliary switch is relied upon to communicate breaker status to a protective relay. If the switch is out of adjustment so that incorrect breaker status is reported to the relay, the relay may not operate when needed. Could proper operation of the auxiliary contacts be credited through in-service operation or the six-year breaker operation maintenance? 4. The term “calendar years” is used to define the maximum intervals. Does this mean that a six-year PM could go one-day shy of seven years? For example, if a six-year maintenance PM was last performed on 1/1/2010, it would be due on 1/1/2016. Could this allow until 12/31/2016 to complete the maintenance? 5. Table 1b, Row 14 (Row 2 on page 17): Under the “Level 2 Monitoring Attributes for Component,” UFLS/UVLS should be referenced instead of SPS. 6. Clarifications need to be made on testing requirements on trip contacts relative to microprocessor vs. EM relays. 7. There appears to be an inconsistency in the use of “check” vs. “verify” in the tables. 8. In battery maintenance table, we suggest that “cell/unit” be changed to “cell or unit.”
Response: Thank you for your comments.		

Organization	Yes or No	Question 1 Comment
1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. 3. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. To the degree that in-service test-operating of the breaker also performs the specified maintenance on other portions of the Protection System, the entity should be able to document and "take credit" for it. 4. Your explanation of "6 Calendar Years" is correct. 5. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5. 6. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-1 and 1-5. 7. "Check" is not an element of the PSMP definition. This term has been replaced throughout the Tables with whatever term of the definition is relevant. **8.** The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4.		
PPL Supply	No	PPL Generation, on behalf of the entities listed above, has the following comments on the dc entries in these tables: 1. Table 1a, Table 1b, Table 1c- Station DC supply - Maintenance Activities - references substation batteries. For generators, shouldn't that reference be station battery? Substation implies an association strictly with transmission, not generation. 2. Station DC supply - verify Battery continuity. What is the technical basis for this requirement? Neither battery installation and operation instructions nor technical reviews explain the basis for how this verification is supposed to work. NERC's Protection System Maintenance: A Technical Reference does not address this requirement. The Frequently-Asked Questions provides some ways that this verification can be completed. However, one example is tied to the microprocessor battery chargers. If there is a technical basis for this requirement, it should be provided. 3. Condition based monitoring on station dc supply - it appears the Table 1b excludes any

Organization	Yes or No	Question 1 Comment
		condition based monitoring of the batteries because of the requirement for monitoring electrolyte level, individual cell state of charge, cell to cell and battery terminal resistance. Most monitoring equipment does not monitor those functions. 4. In general, the Tables are especially confusing in the dc system area. The "lines" overlap and need to be labeled, so they can be referenced in a maintenance document to show how the appropriate program can be followed. Each line should be separate in the function stated, so one can identify what has to be done to comply. 5. Provide examples of "non-battery-based dc equipment" that is covered under this standard. 6. For dc supply, the changes from the Sept. 2007 NERC "Protection System Maintenance", A Technical Reference seem too restrictive. The Sept. 2007 document contained a solid maintenance program. What is the basis for the change?
Response: Thank you for your comments. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. This has been corrected in the revision. 2. Please see the FAQ (I.5.B, I.5.C and I.5.D) 3. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. 4. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. 5. The SDT has been advised that entities are considering or using technologies such as flywheels and fuel cells. Also, we have been told that some entities are using modern battery chargers without the battery. **6.** When developing the original technical reference, the SPCTF was not challenged to develop a complete, measurable Standard. The SDT used the original document as a starting point to develop actual requirements, etc.		
San Diego Gas & Electric	No	1. Proofing of CT circuits is not always trivial. Given this function is not presently being performed and documented by the company, a reasonable grace period would be

Organization	Yes or No	Question 1 Comment
		required to achieve compliance. The company believes present practice, such as verification that relay current inputs are not zero and that phases are balanced, is a reasonable indication individual CTs are functioning properly. 2. An entities protection system maintenance program is a Time Based Maintenance program. The protection system maintenance program describes the maintenance intervals and states that the protection system maintenance is triggered every 4 years. The maintenance program describes that the due date for compliance is 6 months past the trigger date to allow for planning and scheduling of the maintenance activity. Therefore the actual due date for the 4 year maintenance interval is 4 years and six months from the last maintenance completion date. The four year six month time based interval is within the six year maximum time based interval as required by PRC-005-2. Given the above, is the four year six month interval as described in the entities maintenance program compliant with PRC-005-2?
Response: Thank you for your comments. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-3. The intervals remain as prescribed within the Standard and are designed to be effective, clear, and consistently monitored for compliance; the SDT is not prescribing or suggesting what measures an entity may take within their program to assure compliance. “Grace periods” within the Standard are not measurable, and would probably lead to persistently increasing intervals. However, an entity may establish an internal program with grace-period allowance, as long as the entire program (including grace periods) does not exceed the intervals within the Standard. Simply observing non-zero instrument transformer outputs may not be sufficient to determine that the values are acceptable. **2.** “Grace periods” within the Standard are not measurable, and would probably lead to persistently increasing intervals. However, an entity may establish an internal program with grace-period allowance, as long as the entire program (including grace periods) does not exceed the intervals within the Standard.		
Springfield Utility Board	No	SUB appreciates the effort to try to strike a balance between specificity around a specific standard and flexibility to meet the requirement under the standard. The maximum

Organization	Yes or No	Question 1 Comment
		allowable intervals don't seem unreasonable combined with the implementation schedule. However, it seems that the proposed changes stray toward a proscriptive set of maintenance that 1) does not allow for an alternate method of testing and 2) sets unrealistic testing requirements. For example, battery terminal to terminal testing is not feasible with all battery systems. This is a consistent message SUB has heard from others as well. First and foremost - a test or maintenance must be done for each device within the defined interval. With that in mind...SUB's preference would be that the maintenance activities focus on what specifically must be done for a device (may be type specific) vs. what could be done for a device for compliance (as an example of what an auditor could look for when conducting an audit) vs. alternative best-practices for testing and maintenance that the entity demonstrates constitutes as maintenance or test. With regard to the first (maintenance activities focus on what specifically must be done for a device) - it seems that this would apply to a limited number of devices With regard to the second (maintenance activities focus on what specifically can be done for a device) - it seems that this would apply broad number of devices and the list of what can be done should be broad to cover a range of different devices that provide the same function. With regard to the last (alternative best-practices for testing and maintenance that the entity demonstrates constitutes as maintenance or test), it would be helpful to have a mechanism outside the standard itself to either have a NERC technical group craft a series of criteria that must be met for an acceptable alternative maintenance or the entity document the criteria used to determine an adequate test and provide for a test that meets that set of criteria). It would be anticipated that these would fall under a minority of devices.

Response: Thank you for your comments.

Organization	Yes or No	Question 1 Comment
The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5. In the draft Standard, the SDT is defining the basic parameters for an effective PSMP; the entity is required to develop its program with specific activities that would satisfy those basic parameters.		
The Detroit Edison Company	No	Suggest that the interval for cell ohmic testing on VRLA batteries be changed to 12 months. Also, include ohmic testing of NiCad batteries at 18 mos. as an option.
Response: Thank you for your comments. The activity related to this interval is to verify various basic operating parameters. The SDT believes that extension of verification of these parameters beyond the interval within the Standard is inappropriate.		
NorthWestern Corporation	No	Table 1a - Rows 3 & 4 (control and trip circuits) - add language in the Maintenance Activities - "except that verification does not require actual tripping of circuit breakers or interrupting devices"
Response: Thank you for your comments. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5.		
We Energies	No	1. Table 1a, Protective Relays: Change 1st line to: “Test and calibrate if necessary the relays...”Table 1a, Protective Relays: 3rd line: Change “check the relay inputs...” to “verify the relay inputs...”. The term “check” is not defined, whereas “verify” is. Tables 1a & 1b We agree that six / twelve years is an acceptable interval for relay maintenance. 2. Table 1a & 1b, Control & Trip Circuits: The proposed addition to require tripping circuit breakers during Protection System maintenance is detrimental to BES reliability and should be removed. Ï 3. Generating unit protection system maintenance is done during scheduled outages. The high voltage breaker on a generating unit often remains energized to backfeed and supply station auxiliaries when the generator is offline. The proposed requirement will increase the amount of equipment requiring an outage for maintenance, and possibly

Organization	Yes or No	Question 1 Comment
		the length of the outage, resulting in significantly more equipment out of service as well as increased costs. This requirement also results in greater maintenance efforts and costs when there are redundant protection system equipment (breaker trip coils, lockout relays, etc), which is contrary to good practice and reliability. 4. Many of the breakers that We Energies, as the Distribution Provider, trips from its BES protection systems are not owned by We Energies and are owned by a separate transmission company. The trip testing and maintenance of the transmission company may not coincide with our relay maintenance testing program. The standard shall have allowances for the entity to ONLY test or maintain equipment that it OWNS! 5. Table 1a, Station dc supply: a. The activity to verify the state of charge of battery cells is too vague, and requires more specific action. We assume that the drafting committee is recommending specific gravity measurements. Specific gravity measurements have not been shown to an accurate indicator on state of charge. In addition, as shown in the nuclear power industry, there is no established corrective action that is taken based on specific gravity results (eg. Don't require a test where there is no acceptable corrective action). b. The activities to "verify battery continuity" and "check station dc supply voltage" are also vague and need to be more clearly specified what is intended. c. The 3 month time interval for battery impedance testing is too frequent. 18 month or annual testing is more appropriate. d. The 3 calendar year performance or service test is too frequent and will actually remove life from a battery and reduce reliability. Recommend capacity testing no more that every 5 years and more frequent test if the capacity is within 10% of the end of life or design. This is consistent with the nuclear power industry. 6. Table 1b, Station dc supply: Recommend a change or addition to Table 1b - Recommend a level 2 monitoring (not just a default to the level 1 maintenance activities)

Organization	Yes or No	Question 1 Comment
		which allows for the removal of quarterly "check" of electrolyte levels, DC supply voltage, and DC grounds - if station DC supply (charger) voltage is continuously monitored (eg. one should not have detrimental gassing of a battery if the float voltage of the battery is properly set and monitored). 7. Table 1a, Associated communications systems: The requirement to verify functionality every three months is excessive; verifying this every twelve months is adequate. 8. Tables 1a & 1b - Although the latest standard provided some additional clarification, more clarification is required on what maintenance / testing is ONLY required for UFLS/UVLS protection systems vs. BES protection systems (eg. UFLS / UVLS systems - Is a verification of proper voltage of the DC supply the only battery or DC supply required (eg. no state of charge, float voltage, terminal resistance, electrolyte level, grounds, impedance or performance test, etc.)?

Response: Thank you for your comments.

1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-1. "Check" is not an element of the PSMP definition. This term has been replaced throughout the Tables with whatever term of the definition is relevant.
2. These devices contain "moving parts" which must be periodically exercised to remain reliable.
3. The intervals and activities specified are believed by the SDT to be technically effective, in a fashion that may be consistently monitored for compliance. It is left to the the entity to determine how to align these requirements with operational concerns.
4. The SDT contends that "its Protection Systems" is synonymous with "Protection Systems that it owns."
5. a.The SDT is not specifically requiring specific gravity tests, although they may be one effective method of meeting the requirement. Another method is to measure the individual cell voltage. R4 establishes that the entity must initiate resolution of maintenance-correctable issues, so it IS necessary to correct problems that are found.

   b.The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. The SDT does not prescribe specific activities to satisfy the requirements, although some guidance may be found in the FAQ (II.5.B, II.5.C and

Organization	Yes or No	Question 1 Comment
II.5.D) and Supplementary Reference Section 15.4. c. The activity related to this interval is to verify basic operating parameters. The SDT believes that extension of verification of these parameters beyond the interval within the Standard is inappropriate. d. The SDT disagrees, and believes that a performance test at 3-year intervals is appropriate for Valve-Regulated Lead Acid batteries. A properly maintained battery, according to various credible references (from IEEE, EEI, EPRI, various manufacturers, etc.) can easily handle multiple deep discharges over its expected life. 6. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. 7. The SDT believes that the 3-month interval is proper for unmonitored communications systems. **8.** The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4.		
Hydro One Networks	No	1. Table 1a: a. V and I sensing to relays - 12 years? Why not perform this activity with maintenance activities associated with relay maintenance so that they line up? It would only be an incremental amount of work to perform this with associated relay maintenance work b. Removal of requirement for testing of unmonitored breaker trip coils? Is it really the intention of the SDT to remove a requirement that would drive the industry to install TC monitors on breakers to improve reliability? c. UFLS/UVLS DC control and trip circuits - Due to the distributed nature of this program, random failures to trip are not impactive to the overall operation of the UFLS protection. There should be no requirement to check the DC portion of these protections any more often than the DC circuit checks associated with that LV breaker. Since it is clear the requirement does not include the need to trip the breakers why the need to check the trip paths? Deletion of this requirement leaves the requirement to check only the relays and relay trip outputs from the protections every 6 years (or as often as the protective relay component type). d. Along the same lines as the above comment should the maintenance activities for

Organization	Yes or No	Question 1 Comment
		“UVLS and UFLS relays that comprise a protection scheme distributed over the power system” not be the same as “Protective Relays” 2. Table 1c: a. Level 3 attributes for “Associated communications systems” might better read “Evaluating the performance and quality of the channel as well as the performance of any interface to connected protective relays and alarming if the channel/protective relay connections do not meet performance criteria” b. We believe that some of the proposed maintenance intervals for station DC supply are too stringent and that they would not produce significant increase in reliability to justify associated incremental expenditure. For example we suggest that the following changes are considered:- The interval for electrolyte level check for all batteries except VRLAs and internal measured cell/unit Ohmic value for VRLAs be extended to 6 months instead of current time period of 3 months.- The performance or service capacity test of the VRLA battery banks to be extended from 3 years to 5 years.

Response: Thank you for your comments.

1. a. This activity CAN be performed with the relays (for example, every other relay interval) if the entity so desires.
   b. The Tables have been rearranged and considerably revised to simplify and improve clarity. Please see new Table 1-5. Specific to your comment, the SDT initially specified inspection of trip-coil monitoring functions at intervals of 3 calendar months, with tripping otherwise requried annually. This has been revised to simply require tripping at 6-calendar-month intervals.
   c. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5.
   d. This is an intentional difference between UFLS/UVLS and the remainder of the Protection Systems addressed within the Standard, because of the distributed nature of UFLS/UVLS and because these devices are usually tripping distribution system elements.
2. a. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-3.

Organization	Yes or No	Question 1 Comment
b. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4.		
Arizona Public Service Company	No	The associated maintenance activities are too prescriptive. The activities needed to ensure the reliable service of the relay or device should be left up to the discretion of the utility.
Response: Thank you for your comments. The SDT disagrees. In the draft Standard, the SDT is defining the basic parameters for an effective PSMP; the entity is required to develop its program with specific activities that would satisfy those basic parameters.		
Manitoba Hydro	No	1. The monitoring attributes required to achieve level 2 monitoring of Station DC supply seem excessive. We are not aware of any other utilities doing automatic monitoring all 6 attributes required. In particular automatic monitoring of electrolyte level & battery terminal resistance does not seem practical. 2. There is inconsistency between Table 1 and the FAQ. In the Group by Monitoring Level section of the FAQ it indicates that a battery with low voltage alarm would be considered to have level 2 monitoring. 3. In Table 1C under the heading "Maximum Maintenance Interval" some of the entries are stated as being "Continuous". In the case of other maintenance activities the descriptor for Maintenance Interval indentifies the maximum period of time that may elapse before action must be taken. "Continuous" implies continuous action; however, in reality continuous monitoring enables no maintenance action to be taken until such time as trends indicate the need to do so. Therefore we recommend that where the maintenance interval be changed to read "Not Applicable".
Response: Thank you for your comments. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-4. 2. The FAQ has been modified. (See the examples in Section V.) **3.** The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5.		

Organization	Yes or No	Question 1 Comment
MRO's NERC Standards Review Subcommittee (NSRS)	No	The NSRS feels additional changes are needed. 1. The functional testing requirement should be altered or removed as it increases the amount of hands-on involvement and the opportunity for human error related outages to occur, thereby introducing a greater risk to decrease system reliability. As noted on p. 8 in the supplementary reference document, "Experience has shown that keeping human hands away from equipment known to be working correctly enhances reliability." By removing circuits from service on the proposed timelines for functional testing, the chance for human error is greater than a misoperation from faulty wiring. Alternatively, entities may choose to schedule more planned outages to conduct their functional testing in order to limit the risk of unplanned outages resulting from human error. Under this scenario, more elements will be scheduled out of service on a regular basis, thereby reducing transmission system availability and weakening the system making it more challenging to withstand each subsequent contingency (N-1). Thus testing an intact system is more desirable than taking it out of service for testing. 2. While the SDT has included language in the draft standard to use fault analysis to complete maintenance obligations, in practicality, this option does not offer any relief to taking outages to perform functional tests. Nearly all BES circuit breakers are equipped with dual trip coils. Identifying which trip coil operated for a fault only covers the one trip coil. Functional tests would still be needed on the other. The likelihood of having multiple trips on a given line in the course of several years is very low. Given it can take a year to schedule some outages; planning maintenance with random faults is unpractical and will create unacceptable risk to compliance violations. A better approach is to use the basis in schedule A, but extend this to cover the entire protection schemes. The document should establish target goals for mis-operation rates (dependability and security). This would allow the utilities to develop cost effective programs to increase reliability. The utilities would have incentives to replace poorly performing communications systems; they would be able to quantify the value of upgrading relay systems.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. The intervals and activities specified are believed by the SDT to be technically effective, in a fashion that may be consistently monitored for compliance. The entity must determine how to align these requirements with operational concerns.
2. Operational results, if desired by an entity, MAY be used to meet maintenance requirements to the degree that it verifies, etc., the relevant performance. Whether their use is effective for a specific entity is left to the entity to determine. “Maintenance correctable issues”, which may result in part from misoperations, are a part of using Attachment A to develop a performance-based PSMP.</td></tr>
<tr><td>Tennessee Valley Authority</td><td>No</td><td>The requirement to measure internal ohmic values of the station dc supply batteries every 18 months is excessive. The interval should be 36 months. Our experience from performing our routine maintenance program including cell impedance testing at 3-year intervals has been that the program is fully adequate in monitoring bank condition.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. The activity related to this interval is to verify various basic operating parameters. The SDT believes that extension of verification of these parameters beyond the interval within the Standard is inappropriate.</td></tr>
<tr><td>Bonneville Power Administration</td><td>No</td><td>The requirements pertaining to dc control circuitry are confusing.
1. To start with, a definition or further explanation is required for the term “auxiliary contact”. Is this strictly a breaker “a” or “b” switch, or does this include lockout relay contacts, etc.?
2. Another confusing point is that the term trip circuit is used in several places throughout the tables, but it is not included in the definition of Protection System, where the term dc control circuitry is used. It is important to use consistent terminology throughout the definition and the standard.
3. The requirements for (dc) control circuits in Table 1a are fairly straightforward, but in</td></tr>
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Organization	Yes or No	Question 1 Comment
		Table 1b control circuits are broken down into three parts: trip coils and auxiliary relays; trip circuits; and control and trip circuitry. It is very unclear exactly what each of these three parts includes. In Table 1c, control circuitry is covered as a single element. Please provide clarity to what is included in each part of a control circuit in Table 1b and the monitoring attributes of each. Also, please be consistent in the treatment of control circuits throughout the three tables. 4. Table 1a, SPS, BPA does not understand the following segment of this paragraph "The output action may be breaker tripping, or other control action that must be verified, but may be verified in overlapping segments. A grouped output control action need be verified only once within the specified time interval." In one sentence, it says you can test a SPS in segments - and in the next sentence it says you have to verify the grouped output control action at least once within the specified time interval. It seems that the sentences contradict themselves. 5. Table 1b, Control and trip circuitry - "Monitoring of the continuity of breaker trip circuits along with the presence of tripping voltage supply all the way from relay terminals (or from inside the relay) through to the trip coil(s)..." To monitor the trip path as proposed in this Standard would cost some serious time and $$. 6. BPA does not believe there is a way to meet level two monitoring for batteries. In addition, some of the maintenance tasks need to be defined:- monitoring the electrolyte level is not commercially available.- the state of charge of each individual cell may need to be better defined. There are means to verify the state of charge of the entire bank, but not each individual cell. 7. Since a device to provide level 2 monitoring is not commercially available, we would be forced to follow level 1 maintenance guides, which would require maintenance of communication batteries every three months. Many of these batteries are not accessible during 9 months of the year except via snow-cat or helicopter. We currently monitor for some of the level 2 requirements, but not all. Our current practices of monitoring and yearly maintenance supplemented by opportunity inspections have

Organization	Yes or No	Question 1 Comment
		successfully identified problems before we lost DC power to any of our communication facilities. VRLA type batteries: - battery continuity needs to be defined. 8. In regards to the maximum allowable intervals; the frequency with which BPA performs the 18 month maintenance tasks as prescribed in the standard are on a 24 month interval along with visual inspections and voltage measurements weekly to bi-weekly. BPA has seen success with this maintenance program with the ability to identify suspect cells or entire banks with adequate time to perform corrective actions such as repairs or replacements. BPA also does not perform routine capacity testing, this is an as required maintenance task to confirm/validate our other test results if needed. Our suggestion would be to extend the maintenance intervals beyond 18 months, and to provide some clarity on the above items.

Response: Thank you for your comments.

1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. Please see Section 15.3 of the Supplementary Reference Document and the FAQ (II4.E.).
2. The Tables have been rearranged and considerably revised to improve clarity and consistency. Please see new Table 1-5.
3. The Tables have been rearranged and considerably revised to improve clarity and consistency. Please see new Table 1-5.
4. The Tables have been rearranged and considerably revised to improve clarity and consistency. Please see new Table 1-5.
5. The Tables have been rearranged and considerably revised to improve clarity and consistency. Please see new Table 1-5.
6. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. Also, the SDT believes that there are devices available to monitor electrolyte levels.
7. The FAQ (II.5.K) advises that "communications system batteries" are not "station batteries" and are maintained with the communications systems.
8. The activity related to this interval is to verify various basic operating parameters. The SDT believes that extension of verification of these parameters beyond the interval within the Standard is inappropriate.

Organization	Yes or No	Question 1 Comment
Public Service Enterprise Group ("PSEG Companies")	No	The SDT is to be commended for the work and details included in the most recent draft revision. The standard - with associated references is easier to interpret. 1. The sections on DC supply are too restrictive. Quartile checks of VLA electrolyte levels for unmonitored systems is reasonable, however the option of checking the electrolyte levels and voltages with less frequency is not an option with systems that have voltage alarm notification and ground detection monitoring alarm notification unless all level 2 attributes are followed. The level 2 monitoring attributes are too comprehensive to allow for a suggested alternative less restrictive interval of 6 months to a year. Suggest there be an additional option for level 2 monitoring that includes voltage level and ground alarms with a 6 month maintenance activity interval. 2. The perception of table 1a page 12 for station DC supply - “used for UVLS and UFLS” is a maintenance activity to verify proper DC supply voltage when the UVLS and UFLS system is maintained. This is the only DC supply maintenance activity for those applications and the other more rigorous maintenance activities do not apply? If this is a correct interpretation specifically list that as such in the maintenance activity description (State the other DC supply maintenance activities are not applicable for UVLS and UFLS). The maintenance intervals for station DC supply for level 1 and 2 monitoring does not appear to be consistent and is somewhat confusing. A battery system with level 2 monitoring attributes for components has intervals of 6 years, and then in next section states that no level 2 attributes are defined - use level 1 maintenance activities. Suggest that all DC supply / batteries be broken out all be included in one separate - stand alone table with varied maintenance requirements based on monitoring attributes. 3. The maintenance activities shown on table 1b on page 19 for Station DC supply is intended for VLA batteries? If so add that in component definition. 4. For DC systems that use a storage battery, suggest that chargers be eliminated as other required maintenance activities will expose any problems with the charger. 5. The requirements of performing a capacity test every 6 years during the initial service

Organization	Yes or No	Question 1 Comment
		life of a VLA battery in addition to the other maintenance activities are too restrictive and will cause extensive outages of the affected equipment. Suggest that this frequency be extended to 10 years for VLA batteries for the first iteration if all the other maintenance activities are followed. Failure rate of VLA in first 10 years is extremely low. Other maintenance activities will expose significant issues.
Response: Thank you for your comments. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. 2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. 3. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. 4. If the charger fails, the battery will quickly discharge via normal dc loads, and be unable to adequately serve the Protection System. **5.** The SDT disagrees, and believes that a capacity test at 6-year intervals is appropiate for Vented Lead Acid batteries.		
US Bureau of Reclamation	No	1. There is no reliability based justification to alter the standards to include allowable intervals. 2. The intervals prescription for performance based PSMP virtually eliminates the capability of smaller utilities who do not have a large equipment database to justify a performance based system that may be sound based on their experience. This overly prescriptive approach should be eliminated and return to allowing utilities to justify their programs. The standard should return to addressing real reliability impacts as required by law. This would be to develop a maintenance required which identifies that if it is shown that an event in which reliability is impacted by the utilities PSMP, as evidenced by disturbance reports, the utility would be required to submit to the RRO a corrective action plan which addresses how the PSMP will be revised and when compliance with that PSMP is to be achieved. 3. Finally, the standard presumes that components within a BES Element will cause a reliability impact to the BES. In numerous meeting with NERC and WECC it was

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>emphasized that a reliability impact has been described as causing cascading outages or causing loss of service to load above a certain magnitude. The BES has an ability to absorb element outages resulting from a variety of causes without impact load or resulting in cascading outages.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. FERC Order 693 directs NERC to establish maximum allowable intervals.
2. Small entities are permitted to aggregate their components with similar components of other entities to meet the component populations, as long as the programs are (and remain) similar – see Section 9 of the Supplementary Reference, the FAQ (IV.3.A) and the associated footnote to Attachment A. Decreasing the component population below the requirements of Attachment A will result in an unsound program due to component populations that are not statistically significant.
3. 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, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff.</td></tr>
<tr><td>Dynegy Inc.</td><td>No</td><td>We agree with all proposed intervals in Tables 1a, 1b, and 1c except the 3 calendar month interval for Associated Communication Systems in Table 1a. We suggest using a 1 year interval because all other elements of the Protection System are being verified a minimum of every 3 years. Therefore, we believe annual verification of Associated Communication Systems is sufficient.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The SDT believes that the 3-month interval is proper for unmonitored communications systems.</td></tr>
<tr><td>Pacific Northwest Small Public Power Utility Comment Group</td><td>No</td><td>We agree with most of the changes from the last draft. However, the phrase “Verify Battery cell-to-cell connection resistance” has entered the table where it did not exist before. On some types of stationary battery units, this internal connection is inaccessible. On other types the connections are accessible, but there is no way to repair them based on a bad reading. And bad cell-to-cell connections within units will be detected by the other required</td></tr>
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Organization	Yes or No	Question 1 Comment
		tests. This requirement will cause entities to scrap perfectly good batteries just so this test can be performed, with no corresponding increase in bulk electric system reliability while taking an unnecessary risk to personnel and the environment. And because buying battery units composed of multiple cells allows space saving designs, entities may be forced to buy smaller capacity batteries to fit existing spaces. This may end up having a negative effect on reliability. Suggest substituting "unit-to-unit" wherever "cell-to-cell" is used in the table now.
Response: Thank you for your comments. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. This element of the table has been modified to state, "Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)" to address this comment.		
PNGC Power	No	We agree with most of the changes from the last draft. However, the phrase "Verify Battery cell-to-cell connection resistance" has entered the table where it did not exist before. On some types of stationary battery units, this internal connection is inaccessible. On other types the connections are accessible, but there is no way to repair them based on a bad reading. And bad cell-to-cell connections within units will be detected by the other required tests. This requirement will cause entities to scrap perfectly good batteries just so this test can be performed, with no corresponding increase in bulk electric system reliability while taking an unnecessary risk to personnel and the environment. And because buying battery units composed of multiple cells allows space saving designs, entities may be forced to buy smaller capacity batteries to fit existing spaces. This may end up having a negative effect on reliability. Suggest substituting "unit-to-unit" wherever "cell-to-cell" is used in the table now.
Response: Thank you for your comments. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. This element of the table has been modified to state, "Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)" to address this comment.		
FirstEnergy	No	We support most of the maintenance activities detailed in the Tables, but question the

Organization	Yes or No	Question 1 Comment
		verification of battery cell-to-cell resistance. On some types of battery units, this internal connection is inaccessible. We suggest substituting "unit-to-unit" in place of "cell-to-cell".
Response: Thank you for your comments. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. This element of the table has been modified to state, “Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)” to address this comment.		
Florida Municipal Power Agency	No	1. Will the Standard Introduce Technical Feasibility Exceptions to PRC Standards? A large proportion of the batteries (as high as 50% as reported by some SMEs) are not able to accommodate all of the tests prescribed in the draft standard. The phrase “Verify Battery cell-to-cell connection resistance” has entered the table where it did not exist before. On some types of stationary battery units, this internal connection is inaccessible. On other types the connections are accessible, but there is no way to repair them based on a bad reading. And bad cell-to-cell connections within units will be detected by the other required tests. This requirement will cause entities to scrap perfectly good batteries just so this test can be performed, with no corresponding increase in bulk electric system reliability while taking an unnecessary risk to personnel and the environment. And because buying battery units composed of multiple cells allows space saving designs, entities may be forced to buy smaller capacity batteries to fit existing spaces. This may end up having a negative effect on reliability. Suggest substituting “unit-to-unit” wherever “cell-to-cell” is used in the table now. 2. The Standard Reaches Beyond the Statutory Scope of the Reliability Standards As written, the standard requires testing of batteries, DC control circuits, etc., of distribution level protection components associated with UFLS and UVLS. UFLS and UVLS are different than protection systems used to clear a fault from the BES. An uncleared fault on the BES can have an Adverse Reliability Impact and hence; the focus on making sure the fault is cleared is important and appropriate. However, a UFLs or UVLS event happens after the fault is cleared and is an inexact science of trying to automatically restore supply and demand balance (UFLS) or restore voltages (UVLS) to acceptable

Organization	Yes or No	Question 1 Comment
		levels. If a few UFLS or UVLS relays fail to operate out of potentially thousands of relays with the same function, there is no significant impact to the function of UFLS or UVLS. Hence, there is no corresponding need to focus on every little aspect of the UFLS or UVLS systems. Therefore, the only component of UFLS or UVLS that ought to be focused on in the new PRF-005 standard is the UFLS or UVLS relay itself and not distribution class equipment such as batteries, DC control circuitry, etc., and these latter ought to be removed from the standard. In addition, most distribution circuit are radial without substation arrangements that would allow functional testing without putting customers out of service while the testing was underway, or at least without momentary outages while customers were switched from one circuit to another. Therefore, as written, we would be sacrificing customer service for a negligible impact on BES reliability.
Response: Thank you for your comments. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. This element of the table has been modified to state, “Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)” to address this comment. **2.** The Standard addresses UFLS and UVLS to the degree that they are installed per NERC Standards, even though entities may choose to install them on distribution systems.		
NERC Staff	Yes	
PacifiCorp	Yes	
WECC	Yes	Compliance agrees with the changes as they add clarity though the Tables do not define what is actually required to demonstrate compliance without reading the Supplementary Reference and the FAQs.
Response: Thank you for your comments. The Measures do provide discussion of what is required to demonstrate compliance.		

Organization	Yes or No	Question 1 Comment
The United Illuminating Company	Yes	In general yes. There are concerns with verifying cell-to-cell resistance in Batteries. On some battery sets this is not possible to do.
Response: Thank you for your comments. This element of the table has been modified to state, "Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)" to address this comment.		
South Carolina Electric and Gas	Yes	Please provide clarity on why Table 1b for "Station dc supply" has a double entry that appears to be contradictory. The table provides monitoring attributes for a maximum maintenance interval of 6 calendar years and the next row says to refer to level 1 maintenance activities.
Response: Thank you for your comments. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4.		
ReliabilityFirst Corp.	Yes	1. The SDT has made significant and worthwhile changes to these tables. However, these tables still seem overly complex and should be simplified. One possibility would be to eliminate Table 1c and use Table 1b for those components that meet certain monitoring attributes. 2. There are some errors in Table 1a in rows 5 and 6. In row 5 in the component column the word "contact" is missing. In the same row in the third column, there is an extra period. In row 6 in the third column, "circuit" should be "circuits" as in the other rows. 3. The maintenance intervals seem to give preference to solid-state outputs but there is no evidence given that these are truly more reliable than an electromechanical trip at least not sufficient to double the maintenance interval.
Response: Thank you for your comments. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5.		

Organization	Yes or No	Question 1 Comment
2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5. **3.** The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1.		

2. The SDT has included VRFs and Time Horizons with this posting. Do you agree with the assignments that have been made? If not, please provide specific suggestions for improvement.

Summary Consideration: Many commenters disagreed with various VRFs as specified in the draft Standard. The SDT has reconsidered the VRFs in accordance with the guidance provided by NERC and FERC, and the Standard has been modified to assign the VRFs as R1 – Medium, R2 – Medium, R3 – Medium, and R4 – High. Some comments were offered regarding Time Horizons, resulting in modification of the Time Horizons for both R3 and R4 from Long-Term Planning to Operations Planning.

Organization	Yes or No	Question 2 Comment
PPL Supply		No comment.
Xcel Energy		No comments
SERC Protection and Control Sub-committee (PCS)		The SERC PCS expresses no opinion on this question.
San Diego Gas & Electric	No	
The Detroit Edison Company	No	
Black Hills Power	No	
The United Illuminating Company	No	The VRF for R1 should be Low. It is administrative to create an inventory list. If R1 failed to be executed but the other requirements wee executed fully then the BES would be

Organization	Yes or No	Question 2 Comment
		properly secured. Compare this against the scenario of performing R1 but failing to perform the other tasks; in which case the BES is at risk. UI recognizes that the SDT considers the inventory as the foundation of the PSMP but it is not the element of the PSMP that provides for the level of reliability sought. R1 should be VRF Low and R2 thru R4 VRF is Medium. UI agrees with the Time Horizon.
Response: Thank you for your comments. The SDT has reconsidered the VRFs in accordance with the guidance provided by NERC and FERC, and the Standard has been modified to assign the VRFs as R1 – Medium, R2 – Medium, R3 – Medium, and R4 – High.		
JEA	No	1. What role with the Supplementary Reference and FAQ play with reference to the proposed standard? We have a concern that the standard will stand-alone and not include the interpretations, examples and explanations that are needed to properly apply these values in a compliance environment. There needs to be a method to include the FAQ and Supplementary Reference. 2. The method will also need to allow for future modifications as the standard is revised, etc.
Response: Thank you for your comments. 1. The Supplementary Reference and FAQ documents provide supporting discussion, but are not part of the Standard. The SDT intends that these be posted as reference documents, accompanying the Standard. **2.** The SDT intends that these documents be updated as the Standard is revised, such that they continue to be relevant to the application of the Standard.		
FirstEnergy	No	Although we agree that Requirement 1 is important because it establishes a sound PSMP, a HIGH VRF assignment is not appropriate and it should be changed to LOWER. By definition, a requirement with a LOWER VRF is administrative in nature, and documentation of a program is administrative. Assigning a LOWER VRF to R1 is more logical since R4, which is the requirement to implement the PSMP, is assigned a MEDIUM VRF because, if violated, it could directly affect the electrical state or the capability of the bulk electric

Organization	Yes or No	Question 2 Comment
		system. Additionally, revising the VRF to LOWER would provide a consistent assignment to a VRF on a similar requirement in the proposed FAC-003-2 standard.
Response: Thank you for your comments. The SDT has reconsidered the VRFs in accordance with the guidance provided by NERC and FERC, and the Standard has been modified to assign the VRFs as R1 – Medium, R2 – Medium, R3 – Medium, and R4 – High. For a VRF to be classified as "Lower" it must be administrative, and none of the requirements in this standard are 'administrative'.		
Pepco Holdings, Inc. - Affiliates	No	An explanation is needed to justify why the VRF for R1 of the PSMP is High whereas the implementing and following of the PSMP is Medium, R2, R3 & R4.
Response: Thank you for your comments. The SDT has reconsidered the VRFs in accordance with the guidance provided by NERC and FERC, and the Standard has been modified to assign the VRFs as R1 – Medium, R2 – Medium, R3 – Medium, and R4 – High.		
American Transmission Company	No	ATC disagrees with the VRFs as specified in the standard. R1 VRF would more likely be classified as "medium" and R2 through R4 should be classified as a "High" VRF. ATC is O.K. with the Time Horizons specified.
Response: Thank you for your comments. The SDT has reconsidered the VRFs in accordance with the guidance provided by NERC and FERC, and the Standard has been modified to assign the VRFs as R1 – Medium, R2 – Medium, R3 – Medium, and R4 – High.		
Constellation Power Generation	No	Constellation Power Generation questions why the VRF for R1 is High while all other requirements are Medium. This VRF should be changed to Medium to follow suit with the other requirements.
Response: Thank you for your comments. The SDT has reconsidered the VRFs in accordance with the guidance provided by NERC and FERC, and the Standard has been modified to assign the VRFs as R1 – Medium, R2 – Medium, R3 – Medium, and R4 – High.		
Florida Municipal Power Agency	No	R1, R2 and R3 are administrative in nature and ought to be a Low VRF, not a High or Medium VRF. R4 is doing the actual maintenance and testing and ought to be the highest VRF in the standard. Medium VRF is appropriate for R4.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. The SDT has reconsidered the VRFs in accordance with the guidance provided by NERC and FERC, and the Standard has been modified to assign the VRFs as R1 – Medium, R2 – Medium, R3 – Medium, and R4 – High.		
ReliabilityFirst Corp.	No	R4 is the implementation of a maintenance program which is extremely important. Effective operation of the BES is so dependent on adequate maintenance that requirement R4 warrants a High VRF. It seems that requirement R3 may actually be better categorized as having an Operations Assessment Time Horizon as the entity needs to review events to analyze the adequacy of maintenance periods.
Response: Thank you for your comments. The SDT has reconsidered the VRFs in accordance with the guidance provided by NERC and FERC, and the Standard has been modified to assign the VRFs as R1 – Medium, R2 – Medium, R3 – Medium, and R4 – High. The SDT agrees with the suggestion to change the R3 Time Horizon and has assigned an Operations Planning Time Horizon.		
BGE	No	See comments under 7 regarding the ambiguity of R1.1. A high VRF for some interpretations of R1.1 may not be reasonable. A program may be structured so that sufficient maintenance to ensure reliability is taking place even though a specific component is not identified. Contrasting the high VRF for R1 with the medium VRF for R4 seems backwards.
Response: Thank you for your comments. The SDT has reconsidered the VRFs in accordance with the guidance provided by NERC and FERC, and the Standard has been modified to assign the VRFs as R1 – Medium, R2 – Medium, R3 – Medium, and R4 – High.		
MRO's NERC Standards Review Subcommittee (NSRS)	No	The NSRS disagrees with the VRFs as specified in the standard. R1 VRF would more likely be classified as "medium" and R2 through R4 should be classified as a "High" VRF.
Response: Thank you for your comments. The SDT has reconsidered the VRFs in accordance with the guidance provided by NERC and FERC, and the Standard has been modified to assign the VRFs as R1 – Medium, R2 – Medium, R3 – Medium, and R4 – High.		

Organization	Yes or No	Question 2 Comment
US Bureau of Reclamation	No	The Time Horizons are too narrow for the implementation of the standard as written. The SDT appears to have not accounted for the data analysis associated with performance based systems. The data collection, analysis, and subsequent decisions associated development of a maintenance program and its justification do not occur overnight especially with larger utilities. In addition, this new standard will require complete rewrite of maintenance programs. The internal processes associated with these vary based on the size of the utility. Since this standard is so invasive into the internal decisions concerning maintenance, the standard should allow at least 18 months for entities to rewrite their internal maintenance programs to meet the requirements and 18 months to train the staff and implement the new program.
Response: Thank you for your comments. The SDT has reviewed the time horizons, and feels that R1 and R2 are properly assigned a Long-Term Planning Time Horizon, as the activities to develop a program and to determine the monitoring attributes of components are performed within the related time period. The SDT has assigned an Operations Planning Time Horizon to R3 and R4, as some of the related activities must take place within 1-year intervals.		
Ameren	No	The VRF for R1 should be Medium because the failure to do so is commensurate with the risks of the other requirements. For example, failing to establish a PSMP for some portion of the entity's components could lead to their maintenance not meeting this standard; this is the same is establishing the PSMP and then not performing the maintenance per the standard.
Response: Thank you for your comments. The SDT has reconsidered the VRFs in accordance with the guidance provided by NERC and FERC, and the Standard has been modified to assign the VRFs as R1 – Medium, R2 – Medium, R3 – Medium, and R4 – High.		
Indeck Energy Services	No	The VRF's are highly arbitrary because they treat all registered entities and all protective systems alike. They're not. For example, under-frequency relays for generators protect the equipment needed to restore the system after a blackout. The under-frequency load relays prevent a cascading outage. As discussed at the FERC Technical Conference on Standards Development, the goal of the standards program is to avoid or prevent

Organization	Yes or No	Question 2 Comment
		cascading outages--specifically not loss of load. That would make under-frequency load relays more important to prevent cascading outages.
Response: Thank you for your comments. The SDT has reconsidered the VRFs in accordance with the guidance provided by NERC and FERC, and the Standard has been modified to assign the VRFs as R1 – Medium, R2 – Medium, R3 – Medium, and R4 – High. The risk to the system is independent of entity size. VSLs have been modified where necessary to make them independent of size of entity.		
Springfield Utility Board	No	1. Time horizons for implementation seem adequate and SUB appreciates the attention to putting together a reasonable but assertive implementation plan. 2. The Violation Risk Factors are problematic. With all due respect, it seems that NERC still operates in a "BIG UTILITY" mind set. There are "PROTECTION SYSTEMS" and there are "Protection Systems" - some Protection Systems may significantly impact system reliability and others may not. This not promote reliability in that if an entity was thinking about installing a minor system or installing an improvement that enhances reliability (but is not required) that it might back away because of the risk associated with somehow being out of compliance. Reliability runs the risk of being diminished through the standards approach. SUB suggests stepping back and putting more granularity on VRFs and there needs to be more perspective on the purpose of the device when arriving at a risk factor. Perhaps a voltage threshold could be attached to the VRFs. For example language could be added to say "For Elements at 200kV and above, or for Critical Assets, the risk factor is higher" and "For Elements operating at 100kV and above, the risk factor is medium" and "For Elements below 100kV, the risk factor is lower" In SUB's view, a discussion on VRF's needs to coupled with Violation Severity Levels. SUB discusses VRF's later in this comment form. SUB would be supportive of a Medium VRF designation if there were a more balanced VLF structure (please refer to the comments of VLFs)
Response: Thank you for your comments. The SDT has reconsidered the VRFs in accordance with the guidance provided by NERC and FERC, and the Standard has been modified to assign the VRFs as R1 – Medium, R2 – Medium, R3 – Medium, and R4 – High.		

Organization	Yes or No	Question 2 Comment
According to the current Reliability Standards Development Procedure, each Requirement is assigned one (and only one) VRF.		
Manitoba Hydro	No	Time horizons to change from present 6 months to 3 months maintenance time intervals within proposed implementation time period is not realistic.
Response: Thank you for your comments. The options for Time Horizon are Long-Term Planning, Operations Planning, Same-Day Operations, Real-Time Operations, and Operations Assessment. The SDT has reviewed the Time Horizons, and feels that R1 and R2 are properly assigned a Long-Term Planning time horizon, as the activities to develop a program and to determine the monitoring attributes of components is performed within the related time period. The SDT has assigned an Operations Planning Time Horizon to R3 and R4, as some of the related activities must take place within 1-year intervals.		
American Electric Power	Yes	
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	
Consumers Energy Company	Yes	
Duke Energy	Yes	
Dynegy Inc.	Yes	
Entergy Services	Yes	
Exelon	Yes	

Organization	Yes or No	Question 2 Comment
Great River Energy	Yes	
Hydro One Networks	Yes	
Long Island Power Authority	Yes	
MEAG Power	Yes	
MidAmerican Energy Company	Yes	
Northeast Power Coordinating Council	Yes	
Northeast Utilities	Yes	
Pacific Northwest Small Public Power Utility Comment Group	Yes	
PNGC Power	Yes	
Progress Energy Carolinas	Yes	
Public Service Enterprise Group ("PSEG Companies")	Yes	

Organization	Yes or No	Question 2 Comment
Santee Cooper	Yes	
South Carolina Electric and Gas	Yes	
Southern Company Transmission	Yes	
Tennessee Valley Authority	Yes	
We Energies	Yes	
Western Area Power Administration	Yes	
Y-W Electric Association, Inc.	Yes	
PacifiCorp	Yes	Agree with the exception that the time horizon for implementation needs to recognize that documentation for maintenance tasks performed prior to this standard may not match current requirements and there should be no penalty for this.
Response: Thank you for your comments. The Implementation Plan needs to address the concerns expressed.		
Nebraska Public Power District	Yes	Please provide an example of how the compliance percentage will be calculated for the implementation plan.
Response: Thank you for your comments. The SDT does not understand how this comment relates to the VRFs or to the Time Horizons.		

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

Summary Consideration: Many commenters expressed concern about the data retention requirements for two full maintenance intervals, and the SDT responded that this is consistent with today's expectations of many Compliance Monitors. Other commenters were concerned about data retention over the transition from PRC-005-1 to two full maintenance intervals for PRC-005-2, and the SDT offered advice that, until two maintenance cycles have been experienced under PRC-005-2, the program and associated documentation for PRC-005-1 will still be relevant.

Comments were offered that "on-site" audits as expressed in the Data Retention Section (item 1.3 under Compliance) are not relevant for small entities which are not audited on-site; the SDT agrees and changed the term to "scheduled" audits.

Several commenters offered suggestions relative to the Measures, resulting in changes to all four Measures. The SDT removed the detailed Protection System definition from Measure M1, inserted "Distribution Provider" in Measure M2, and made changes to consistently use "shall" rather than "will" or "should" throughout all the Measures.

Organization	Yes or No	Question 3 Comment
WECC		1. Compliance agrees with the measures. 2. Compliance recommends making the Supplementary Reference part of the standard and that it be referenced appropriately in Table 1a, 1b, 1c and Attachment A. 3. Compliance does not agree with the Data Retention as provided in the draft. In order for an entity to demonstrate that they have maintained system protection elements within their defined intervals retention of documentation will be required for many years.

Organization	Yes or No	Question 3 Comment
		This is in order to establish bookends for the maintenance interval. Maintenance intervals commonly span 5 years or more. Entities should be required to retain data for the entire period of the maintenance interval. Data Retention should be changed to: The Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generation Owner that owns a generation Protection System, shall retain evidence of the implementation of its Protection System maintenance and testing program for a minimum of the duration of one maintenance interval as defined in the maintenance and testing program.
Response: Thank you for your comments. 1. Thank you. 2. This document provides supporting discussion, but is not part of the Standard. The SDT intends that it be posted as a Reference Document, accompanying the Standard. As established in SDT Guidelines, 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 Document. **3.** The SDT believes that the modification suggested in the comment is not sufficient to demonstrate compliance. In order that a Compliance Monitor can be assured of compliance, the SDT 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. The SDT has specified the data retention in the posted Standard to establish this level of documentation.		
Xcel Energy		No comments
San Diego Gas & Electric	No	
The Detroit Edison Company	No	
Ameren	No	1) M2 incorrectly excludes Distribution Provider. 2) For those components with numerous cycles between on-site audits, retaining and

Organization	Yes or No	Question 3 Comment
		providing evidence of the two most recent distinct maintenance performances and the date of the others should be sufficient. If an entity misses a required maintenance, that results in a self report. We are subject to spot audits and inquiries at any time between on-site audits as well. 3) For those components with cycles exceeding on-site audit interval, retaining and providing evidence of the most recent distinct maintenance performance and the date of the preceding one should be sufficient. Auditors will have reviewed the preceding maintenance record. Retaining these additional records consumes resources with no reliability gain. 4) FAQ II 2B final sentence states that documentation for replaced equipment must be retained to prove the interval of its maintenance. We oppose this because: the replaced equipment is gone and has no impact on BES reliability; and such retention clutters the data base and could cause confusion. For example, it could result in saving lead acid battery load test data beyond the life of its replacement.
Response: Thank you for your comments. 1. Distribution Provider has been added to Measure M2. 2. The SDT understands that Compliance Monitors will usually wish to review data to review program performance back to the preceding on-site audit. **3.** The SDT 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. The SDT has specified the data retention in the posted Standard to establish this level of documentation. The SDT understands that Compliance Monitors are currenlty requesting data on retired components to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance), and believes that this suggestion in the FAQ is appropriate.		
Northeast Power Coordinating Council	No	1. Clarification is needed for “on-site audit” - does it include audits by any of the following - NPCC/NERC/FERC. Several small entities do not have on-site audits and participate in

Organization	Yes or No	Question 3 Comment
		off-site audits. Hence, suggest deleting “on-site” from the requirement. 2. Further clarification is required to the Data Retention section to coordinate with the statement in FAQ (Section IV.d p. 22 redline). Suggest the following revised Data Retention requirement consistent with the statement and example given in FAQ:”The Transmission Owner, Generator Owner, and Distribution Provider shall each retain at least two maintenance test records or statistical data to demonstrate compliance with test interval required for each distinct maintenance activity for the Protection System components. The Compliance Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent compliance records.”
Response: Thank you for your comments. 1. We have modified “on-site” to “scheduled” to address this comment. **2.** The SDT was unable to locate the discussion from the comment within the FAQ.		
Constellation Power Generation	No	Constellation Power Generation does not agree with the proposed data retention section. Retaining and providing evidence of the two most recent performances of each distinct maintenance activity should be sufficient. For entities that have not been audited since June of 2007, having to retain evidence from that date to the date of an audit could contain numerous cycles, which is cumbersome and does not improve the reliability of the BES.
Response: Thank you for your comments. For shorter-interval activities (such as those with quarterly intervals), the SDT understands that Compliance Monitors are currently requesting data to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance) or for the duration specified in a standard.		
JEA	No	Data retention becomes a complex issue for maintenance intervals of 12 years where the last two test intervals are required to be kept, i.e. 24 years. It would seem much more reasonable to set a limit of two test intervals or the last regional audit, not having to keep some 24 years of documentation with maintenance systems changing and archival records

Organization	Yes or No	Question 3 Comment
		somewhat problematic to keep.
Response: Thank you for your comments. In order that a Compliance Monitor can be assured of compliance, the SDT 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. The SDT has specified the data retention in the posted standard to establish this level of documentation.		
Public Service Enterprise Group ("PSEG Companies")	No	Data retention for battery capacity test should be most recent performance, not last 2. The other maintenance activities documentation with one iteration of capacity test is sufficient documentation
Response: Thank you for your comments. In order that a Compliance Monitor can be assured of compliance, the SDT 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, as well as data to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The SDT has specified the data retention in the posted Standard to establish this level of documentation.		
PacifiCorp	No	Data retention requirements need to be modified. The need to maintain records of two previous tasks is excessive, one should be adequate. Per the two previous task requirements an entity may need to maintain records for 35 years.
Response: Thank you for your comments. In order that a Compliance Monitor can be assured of compliance, the SDT 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, as well as data to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The SDT has specified the data retention in the posted Standard to establish this level of documentation.		
Progress Energy Carolinas	No	M2 incorrectly excludes Distribution Provider.
Response: Thank you for your comments. Measure M2 has been modified to add "Distribution Provider."		
Duke Energy	No	M4 states that entities shall have evidence such as maintenance records or maintenance summaries (including dates that the components were maintained). We would like to see

Organization	Yes or No	Question 3 Comment
		M4 revised/expanded to explicitly include the FAQ Section IV 1.B information which states that forms of evidence that are acceptable include, but are not limited to: o Process documents or plans o Data (such as relay settings sheets, photos, SCADA, and test records) o Database screen shots that demonstrate compliance information o Diagrams, engineering prints, schematics, maintenance and testing records, etc. o Logs (operator, substation, and other types of log) o Inspection forms o U.S. or Canadian mail, memos, or email proving the required information was exchanged, coordinated, submitted or received o Database lists and records o Check-off forms (paper or electronic) o Any record that demonstrates that the maintenance activity was known and accounted for.
Response: Thank you for your comments. The Standard Development Procedure requires that Measures provide some examples of evidence, but does not require an exhaustive list. The SDT did add "check-off lists" and "inspection records."		
Indeck Energy Services	No	Measure 1 is complete overkill for a small generating facility. The maintenance program is to inspect and test the equipment within the intervals. A qualified contractor applies industry standard methods to maintain the equipment. Trying to have each entity define the maintenance program down to the component level does not improve reliability.
Response: Thank you for your comments. A definition of "Component" has been added to the draft PRC-005-2 Standard to help explain how "component" can be characterized.		

Organization	Yes or No	Question 3 Comment
PPL Supply	No	1. Measurers M1 - requires having a maintenance program that addresses control circuitry associated with protective functions from the station dc supply through the trip coil(s) of the circuit breakers. Some generators do not own this equipment to the circuit breaker or other interrupting devices. The requirement should be to maintain and test the equipment owned by the generator. 2. Data Retention 1.3 references on-site audits. Entities registered as GO and GOP are not audited on-site.
Response: Thank you for your comments. 1. The SDT believes that “its Protection Systems” in Requirement R1 is synonymous with “Protection Systems that it owns” and declines to modify the Standard to address this comment. **2.** We have modified “on-site” to “scheduled” to address this comment.		
Arizona Public Service Company	No	The change to the Protection System definition and establishing a PSMP with prescriptive maintenance activities relative to the voltage and current sensing devices has created a situation where data from original or prior verification not being available or not at the interval to meet the data retention requirement. Although, methods of determining the integrity of the voltage and current inputs into the relays were used to ensure reliability of the devices meets the utilities requirements, they may not meet the interval requirement and would then be considered a violation due to changes in the standard. Recommend a single exemption of the two recent most recent performances of maintenance activities to the most recent performance of maintenance activity in the first maintenance interval for this component due to the long maintenance interval, the changes in the standard definitions and the prescriptive maintenance activities.
Response: Thank you for your comments. The SDT believes that Compliance Monitors will assess compliance for activities performed before the effective date of this Standard using the program that you had in place previously.		

Organization	Yes or No	Question 3 Comment
American Electric Power	No	1. The measure includes the entire definition of "Protection System". Remove the definition from the measure and let the definition stand alone in the NERC glossary. 2. 1.3 Data Retention This calls for past 2 distinct maintenance records to be kept. Since UFLS interval can be 12 years, this would mean that we would need to keep records for 24 years. This is not realistic and consideration should be given to choosing a reasonable retention threshold.
Response: Thank you for your comments. 1. Measure M2 has been modified as suggested. **2.** In order that a Compliance Monitor can be assured of compliance, the SDT 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, as well as data to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The SDT has specified the data retention in the posted Standard to establish this level of documentation.		
Springfield Utility Board	No	The measures do not seem unreasonable. However the data retention states that documentation must exist for the two most recent performances of each maintenance activity. Stepping back, there is an implementation schedule that is designed to bring all devices into compliance with ONE maintenance or test within (SUB's understanding is) 6 years. There may not be documentation for more than one activity. Further, new or replacement components won't have more than one activity for a number of years. The data retention schedule, left unchanged, will promote non-compliance because it is impossible to have two records when only one may possibly exist. Rather than promote a culture of compliance, the standard promotes a culture of non-compliance by creating an standard that cannot be met. The FAQ addresses this issue, but the Data Retention language seems to be less clear. SUB suggests that the Data Retention language be clear that new components that do not replace existing components may have only one record for maintenance if only one maintenance of the component could possibly exist. SUB suggests that the Data Retention language also be clear that for new components that

Organization	Yes or No	Question 3 Comment
		replace existing components, that the Data Retention requirement reflect that the entity needs to retain the last test for the pre-existing component and the test for the new component (for a total of two tests).
Response: Thank you for your comments. First of all, the Data Retention presumes a stable Standard that has been in effect. Further, the SDT believes that Compliance Monitors will assess compliance for activities performed before the effective date of this Standard using the program that you had in place previously. Therefore, the documentation for your program under PRC-005-1 (whatever it may have been) will serve as your "second interval" documentation until supplanted by new PRC-005-2 records.		
US Bureau of Reclamation	No	The measures M2, M3, and M4 are redundant to measure M1. Either eliminate M1 or M2 through M4. The entity must provide documentation of its maintenance program in M1 irrespective of the type used. As previously mentioned there is not reliability based justification for the documentation required. The Entity should be afforded the freedom to make intelligent maintenance choices based on innumerable factors. These choices will be reviewed if a reliability impact is determined to be related to the choices.
Response: Thank you for your comments. The NERC Reliability Standard Development Procedure establishes that each individual requirement will have its own Measure. Additionally, the four Measures are NOT redundant – Measure M1 addresses "having a program," Measure M2 addresses "monitoring attributes to use extended intervals in the Tables," Measure M3 addresses "criteria for a performance-based program," and Measure M4 addresses "implementation of the program."		
American Transmission Company	No	The NERC standard assigns a retention period for the two most recent performances of maintenance activity which implies two intervals of documentation be maintained. ATC does not agree that requiring all data for two full cycles is warranted. The volume and length of data retention is unreasonable. ATC recommends that the entity retain the last test date with the associated data, plus the prior cycle test date only without retaining the test data. ATC agrees with assignment of the measures.
Response: Thank you for your comments. In order that a Compliance Monitor can be assured of compliance, the SDT 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		

Organization	Yes or No	Question 3 Comment
one. The SDT has specified the data retention in the posted Standard to establish this level of documentation.		
MRO's NERC Standards Review Subcommittee (NSRS)	No	The NERC standard assigns a retention period for the two most recent performances of maintenance activity which implies two intervals of documentation being maintained. The NSRS does not agree that requiring all data for two full cycles is warranted. The volume and length of data retention is unreasonable. The NSRS recommends that the entity retain the last test date with the associated data, plus the prior cycle test date only without retaining the test data.
Response: Thank you for your comments. In order that a Compliance Monitor can be assured of compliance, the SDT 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. The SDT has specified the data retention in the posted Standard to establish this level of documentation.		
Pepco Holdings, Inc. - Affiliates	No	The present wording regarding data retention states - The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation of the two most recent performances of each distinct maintenance activity for the Protection System components, or to the previous on-site audit date, whichever is longer. This wording was changed by the SDT following comments received from Draft 1. However, the present wording is somewhat confusing. It is assumed that the intent of the SDT was to require documentation be retained for the two most recent performances of each distinct maintenance activity, regardless of when they occurred (i.e., whether prior to, or since the last audit), since the phrase whichever is longer was used. In addition, for those activities requiring short maintenance intervals (such as battery inspections), records must be kept for all performances (not just the last two) that have taken place since the last on-site audit. For example: Assume a PSMP with a 6 year interval for relay maintenance and 3 month interval for battery inspections. At a particular station assume the batteries have been inspected every 3 months; the relays were last inspected 5 years ago, and before that 11 years ago. The last audit was 2 years ago. Records from each 3 month battery inspection going back to the last audit needs to be retained. Also, both relay maintenance records from 5 and 11 years ago needs to be retained, despite the fact that this interval should

Organization	Yes or No	Question 3 Comment
		have been reviewed during the last audit. Documentation from the 11 year ago activity can be discarded when the relays are next maintained. Is this what the SDT intended? If so, the requirement should be re-worded to better explain the intent. Also, examples should be included in either the FAQ or Supplemental Reference to demonstrate what is expected.
Response: Thank you for your comments. You understand the data retention correctly as intended by the SDT and specified in the draft standard. In order that a Compliance Monitor can be assured of compliance, the SDT 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, as well as data to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The SDT has specified the data retention in the posted Standard to establish this level of documentation. .		
We Energies	No	The requirement to retain data for the two most recent maintenance cycles is excessive. The required data should be limited to the complete data for the most recent cycle, and only the test date for the previous cycle.
Response: Thank you for your comments. In order that a Compliance Monitor can be assured of compliance, the SDT 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. The SDT has specified the data retention in the posted Standard to establish this level of documentation.		
Long Island Power Authority	No	1. Two most recent performances of each distinct maintenance activity for the Protection System components will require data retention for an extended period of time. For example, in certain cases, battery maintenance is on a 12 year cycle which suggests that records need to be retained for 24 years. LIPA suggests retaining data for the most recent maintenance activity. 2. LIPA seeks clarification on “on-site audit” - does it include audits by any of the following - NPCC/NERC/FERC. Also, several small entities do not have on-site audits and participate in off-site audits. Hence, LIPA suggests deleting “on-site” from the requirement. In addition further clarification is required to the Data Retention section to

Organization	Yes or No	Question 3 Comment
		coordinate with the statement in FAQ (Section IV.d p. 22 redline).
Response: Thank you for your comments. **1.** In order that a Compliance Monitor can be assured of compliance, the SDT 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; thus, records for maintenance which is performed every 12 years will need to be retained for 24 years.. The SDT has specified the data retention in the posted Standard to establish this level of documentation. Audits may be by any of the entities listed. The term “on-site” has been replaced by “scheduled” to address your concern.		
Northeast Utilities	No	Two most recent performances of each distinct maintenance activity for the Protection System components will require data retention for an extended period of time. From the FAQ, it is understood that “the intent is not to have three test result providing two time intervals, but rather have two test results proving the last interval”. However two intervals still results in an extended period of time. For example, for a twelve year interval, data would need to be retained for ~24 years. During that period of time a number of on-site audits would have been completed - it is not clear why the requirement is the longer of the two most recent performances or to the previous on site audit date.
Response: Thank you for your comments. In order that a Compliance Monitor can be assured of compliance, the SDT 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. The SDT has specified the data retention in the posted Standard to establish this level of documentation.		
MidAmerican Energy Company	No	Verification of compliance with the maximum time intervals for testing only needs to include retention of the documentation of the two most recent maintenance activities. The phrase “or to the previous on-site audit (whichever is longer)” should be deleted.
Response: Thank you for your comments. In order that a Compliance Monitor can be assured of compliance, the SDT 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, as well as data to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory		

Organization	Yes or No	Question 3 Comment
compliance). The SDT has specified the data retention in the posted Standard to establish this level of documentation.		
BGE	Yes	
Black Hills Power	Yes	
Bonneville Power Administration	Yes	
Consumers Energy Company	Yes	
Dynegy Inc.	Yes	
Entergy Services	Yes	
Exelon	Yes	
Great River Energy	Yes	
Hydro One Networks	Yes	
MEAG Power	Yes	
Pacific Northwest Small Public Power Utility Comment Group	Yes	
PNGC Power	Yes	

Organization	Yes or No	Question 3 Comment
ReliabilityFirst Corp.	Yes	
Southern Company Transmission	Yes	
The United Illuminating Company	Yes	
Western Area Power Administration	Yes	
Y-W Electric Association, Inc.	Yes	
South Carolina Electric and Gas	Yes	(Note that Section C.M2 leaves off "Distribution Provider" but references Requirement R2 at the end of the Section. "R2 applies to the Distribution Provider.")
Response: Thank you for your comments. Measure M2 has been modified to add "Distribution Provider.".		
Nebraska Public Power District	Yes	Additional guidance on what is acceptable evidence is always good.
Response: Thank you for your comments. In addition to the lists within the Measures, the FAQ (IV.1.B) and Section 15.7 of the Supplementary Reference Document provide additional guidance about acceptable evidence.		
Florida Municipal Power Agency	Yes	M1 could be shortened to just a program in accordance with R1, rather than repeat the entire requirement
Response: Thanks you for your comments. The restatement of the definition has been removed from Measure M1, but the Reliability		

Organization	Yes or No	Question 3 Comment
Standards Development Procedure specifies that Measures contain levels of detail similar to Measure M1 as posted.		
NERC Staff	Yes	Make sure that the use of verbs like “shall,” “should,” and “will” is consistent across Requirements and Measures. In these four measures, all three verbs are used, and they should be made uniform to avoid misinterpretation.
Response: Thank you for your comments. The Measures have been modified to consistently use “shall.”		
Manitoba Hydro	Yes	No issues or concerns at present
Response: Thank you.		
SERC Protection and Control Sub-committee (PCS)	Yes	The SERC PCS expresses no comments on this question.
Response: Thank you.		
FirstEnergy	Yes	We agree with the Measures but suggest some improvements: 1. In Measures M2 and M3, the term "should" must be changed to "shall" 2. In Measure M2, the Distribution Provider entity is missing
Response: Thank you for your comments. 1. Measure M2 and Measure M3 have been modified as suggested. **2.** Distribution Provider has been added to Measure M2.		
Santee Cooper	Yes	We are concerned with the long-term implementation of the data retention requirements for activities with long maximum intervals. For example, if you are performing an activity that is required every 12 years, the implementation plan says that you should be 100% compliant

Organization	Yes or No	Question 3 Comment
		in 12 years following regulatory approval. However, assuming that 100% compliant meant that you got through all of your components once, you still would not be able to show the last two test dates. 12 years from now, would you still have to discuss the program you were using prior to 12 years ago for those components to have a complete audit, because of having to address the last 2 test dates?
Response: Thank you for your comments. First of all, the Data Retention presumes a stable Standard that has been in effect. Further, the SDT believes that Compliance Monitors will assess compliance for activities performed before the effective date of this Standard using the program that you had in place previously. Therefore, the documentation for your program under PRC-005-1 (whatever it may have been) will serve as your “second interval” documentation until supplanted by new PRC-005-2 records.		

4. The SDT has included VSLs with this posting. Do you agree with the assignments that have been made? If not, please provide specific suggestions for change.

Summary Consideration: Many commenters were concerned about the basis for the percentage increments for different severities of VSLs; these commenters were referred to the VSL Guidelines which propose a Lower VSL as noncompliant with “5% or less,” the Medium VSL as “more than 5% but less than (or equal to) 10%,” the High VSL as “more than 10% up to (and including) 15%,” and the Severe VSL as “more than 15% noncompliant.”.

Similarly, many commenters suggested that binary VSLs be assigned a Lower or High rather than a Severe, and were also referred to the VSL Guidelines which indicate that total noncompliance with a requirement is a Severe VSL. VSLs are not indicators of “importance” or “reliability-related risk” – VSLs are an indication of the degree of noncompliant performance.

The VSL for Requirement R4 was modified to add stepped VSLs relating to resolution of maintenance-correctable issues in response to several comments.

Several commenters suggested that the Lower VSL for R4 start at 1% rather than 5%, which is not in accordance with the VSL Guidelines.

Organization	Yes or No	Question 4 Comment
PPL Supply		No Comment.
Xcel Energy		No comments
San Diego Gas & Electric	No	
The Detroit Edison	No	

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td>Company</td><td></td><td></td></tr>
<tr><td>GDS Associates</td><td>No</td><td>1. We do agree with the majority of the assignments that have been made, however the standard needs specific guidance so to be clearly evidentiated the components as included in the definition of Protection System. The applicability of the standard does not address the current issues regarding radial + load serving only situation when Protection System not designed to provide protection for the BES.
2. Not sure if the percentages corresponding to the events and activities are appropriately assigned. What were the criteria on which all these percentages are based upon?
3. Requirement R3 Severe VSL note 3 allows smaller segment population than the Lower VSL. How these segment limits were developed?</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. This is an issue related to your Regional BES definition, not to the VSLs.
2. The VSL Guidelines, developed in accordance with the FERC VSL Order, establish the Lower VSL for stepped VSLs as “5% or less,” the Medium VSL as “more than 5% but less than (or equal to) 10%,” the High VSL as “more than 10% up to (and including) 15%,” and the Severe VSL as “more than 15%.”
3. The segment limits for Requirement R3 and Attachment A were developed according to statistical references to assure that performance-based programs are based on a statistically-significant population. See Section 9 of the Supplementary Reference Document. The Lower VSL addresses “a slightly smaller segment population” than specified; the Severe VSL addresses “a significantly smaller segment population” than specified.</td></tr>
<tr><td>Ameren</td><td>No</td><td>1) The Lower VSL for all Requirements should begin above 1% of the components. For example for R4: “Entity has failed to complete scheduled program on 1% to 5% of total Protection System components.” 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</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
		reliability in that valuable resources will be distracted from other duties. 2) In R1, a “Failure to specify whether a component is being addressed by time-based, condition-based, or performance-based maintenance” by itself is a documentation issue and not an equipment maintenance issue. Suggest this warrants only a lower VSL, especially when one of the required components can only be time based. It is possible that a component that failed to be individually identified per R1.1 was included by entity A’s maintenance plan. This documentation issue gets a higher VSL than entity B that identified a component without maintaining it. We suggest the R1 VSL be change to Low, since we believe lack of maintenance to be more severe than documentation issues.
Response: Thank you for your comments. 1. The SDT shares your concerns regarding the Lower VSL portion of the stepped VSLs not providing any tolerance for non-conformance without being non-compliant. However, the VSL Guidelines, which conform to the FERC VSL Order, specify that Lower shall be “5% or less.” **2.** The VSL for Requirement R1 addresses various levels of severity for degrees of non-compliance. The VSL Guidelines, developed in accordance with the FERC VSL Order, establish that if only a single VSL is provided, it must be Severe. The reliability-related risk related to noncompliance with this requirement is addressed by the VRF being assigned as Lower.		
Entergy Services	No	1. R4: A “Failure to specify whether a component is being addressed by time-based, condition-based, or performance-based maintenance” by itself is a documentation issue and not an equipment maintenance issue. Suggest this warrants only a lower VSL, especially when one of the required components can only be time based. 2. R4: Suggest a stepped VSL for “Entity has failed to initiate resolution of maintenance-correctable issues”. While we understand the importance of addressing a correctable issue, it seems like there should be some allowance for an isolated unintentional failure to address a correctable issue. If possible, consider the potential impact to the system. For example, a failure to address a pilot scheme correctable issue for an entity that only employs pilot schemes for system stability applications should not necessarily have the

Organization	Yes or No	Question 4 Comment
		same VSL consequence as an entity which employs pilot schemes everywhere on their system as a standard practice.
Response: Thank you for your comments. 1. This actually addresses the VSL for Requirement R1, which addresses various levels of severity for degrees of non-compliance. The risk related to this is addressed by the VRF being assigned as Lower. **2.** The VSL for Requirement R4 has been modified to provide stepped VSLs for initiation of resolution of maintenance-correctable issues.		
WECC	No	Compliance does not agree. The R1 VSL allows too much to interpret. What does no more than 5% of the component actually use to define the percentage; it should be specific if it is referring to the weight of each component and how many components are there. For example, Protective Relay is one component of five. In addition the VSL for Lower, Moderate and High states in the first paragraph that the entity included all of the "Types" of components according to the definition, though failed to "Identify the Component". It needs clarity on how it can be included though not specifically identified like the next two bullets. The same concern applies to R2 and R4. Be specific about what is included (or not) to calculate those percentages.
Response: Thank you for your comments. The percentages will depend to a large degree how the entity describes their components. A definition of "Component" has been added to the Standard to provide guidance and help provide consistency.		
Constellation Power Generation	No	Constellation Power Generation does not agree with the proposed data retention section. Retaining and providing evidence of the two most recent performances of each distinct maintenance activity should be sufficient. For entities that have not been audited since June of 2007, having to retain evidence from that date to the date of an audit could contain numerous cycles, which is cumbersome and does not improve the reliability of the BES.
Response: Thank you for your comments. This comment is not relevant to VSLs. In order for a Compliance Monitor to be assured of		

Organization	Yes or No	Question 4 Comment
compliance, the SDT 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, as well as data to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The SDT has specified the data retention in the posted Standard to establish this level of documentation.		
Northeast Utilities	No	For R1 under Severe VSL - suggest moving the first criteria “The entity’s PSMP failed to address one or more of the type of components included in the definition of “Protection System” under High VSL since this criteria cannot have the same VSL level as “Entity has not established a PSMP”.
Response: Thank you for your comments. The SDT believes that, if an entity has missed one (of the five) entire component types in their program, they do not have a complete program.		
Florida Municipal Power Agency	No	1. For the VSLs of R1 and R2, we do not understand where the 5%, 10% come from. There are only a few types of components, relays, batteries, current transformers and voltage transformers, DC control circuitry, communication, that’s 6 component types by our count, so, missing 1 component type in discussing the type of maintenance program is already a 17% error and Low, Medium and High VSLs are meaningless as currently drafted and every violation would be Severe, was the intention to apply this is a different fashion? 2. Perfection is Not A Realistic Goal R4 allows no mistakes. Even the famous six sigma quality management program allows for defects and failures (i.e., six sigma is six standard deviations, which means that statistically, there are events that fall outside of six standard deviations). PRC-005 has been drafted such that any failure is a violation, e.g., 1 day late on a single relay test of tens of thousands of relays is a violation. That is not in alignment with worldwide accepted quality management practices (and also makes audits very painful because statistical, random sampling should be the mode of audit, not 100% review as is currently being done in many instances). FMPA suggests considering statistically based performance metrics as opposed to an unrealistic performance target that does not allow for any failure ever. Due to the shear volume of

Organization	Yes or No	Question 4 Comment
		relays, with 100% performance required, if the standards remain this way, PRC-005 will likely be in the top ten most violated standards for the forever. In other words, 1-2% of components outside of the program should be allowed without a violation and Low VSL should start at a non-zero number, such as “Entity failed to complete scheduled program for 3-6% of components based on a statistically significant random sampling” or something to that affect. 3. There is a fundamental flaw in thinking about reliability of the BES. We are really not trying to eliminate the risk of a widespread blackout; we are trying to reduce the risk of a widespread blackout. We plan and operate the system to single and credible double contingencies and to finite operating and planning reserves. To eliminate the risk, we would need to plan and operate to an infinite number of contingencies, and have an infinite reserve margin, which is infeasible. Therefore, by definition, there is a finite risk of a widespread blackout that we are trying to reduce, not eliminate, and, by definition, by planning and operating to single and credible double contingencies and finite operating and planning reserves, we are actually defining the level of risk from a statistical basis we are willing to take. With that in mind, it does not make sense to require 100% compliance to avoid a smaller risk (relays) when we are planning to a specified level of risk with more major risk factors (single and credible double contingencies and finite planning and operating reserves).

Response: Thank you for your comments.

1. The VSL Guidelines, developed in accordance with the FERC VSL Order, establish the Lower VSL for stepped VSLs as “5% or less,” the Medium VSL as “more than 5% but less than (or equal to) 10%,” the High VSL as “more than 10% up to (and including) 15%,” and the Severe VSL as “more than 15%.” Much of this comment seems to relate to the VSL for Requirement R1; this VSL has been extensively revised, and additional terms have been added to the Definitions section to clarify.
2. The SDT shares your concerns regarding the Lower VSL portion of the stepped VSLs not providing any tolerance for non-conformance without being non-compliant. However, the VSL Guidelines, which conform to the FERC VSL Order, specify that Lower shall be “5% or less.” The VRF and VSLs are only a starting point in determining the size of a penalty or sanction – the

Organization	Yes or No	Question 4 Comment
Compliance Enforcement Authority has latitude to consider aggravating factors and mitigating factors in determining whether there should be any penalty, and the size of any penalty. These mitigating and aggravating factors are oultined in the Compliance Monitoring and Enforcement Program. http://www.nerc.com/files/Appendix4C_Uniform_CMEP_10022009.pdf **3.** 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, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff. The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation.		
Santee Cooper	No	In R1, a “Failure to specify whether a component is being addressed by time-based, condition-based, or performance-based maintenance” by itself is a documentation issue and not an equipment maintenance issue. Suggest this warrants only a lower VSL, especially when one of the required components can only be time based.
Response: Thank you for your comments. The VSL for Requirement R1 addresses various levels of severity for degrees of non-compliance.		
SERC Protection and Control Sub-committee (PCS)	No	In R1, a “Failure to specify whether a component is being addressed by time-based, condition-based, or performance-based maintenance” by itself is a documentation issue and not an equipment maintenance issue. Suggest this warrants only a lower VSL, especially when one of the required components can only be time based.
Response: Thank you for your comments. The VSL for Requirement R1 addresses various levels of severity for degrees of non-compliance.		
Progress Energy Carolinas	No	In the VSL for R1, a failure to “specify whether a component is being addressed by time-based, condition-based, or performance-based maintenance” by itself is a documentation issue and not an equipment maintenance issue. Suggest this warrants only a lower VSL, especially when one of the required components can only be time based.
Response: Thank you for your comments. The VSL for Requirement R1 addresses various levels of severity for degrees of non-		

Organization	Yes or No	Question 4 Comment
compliance.		
Pacific Northwest Small Public Power Utility Comment Group	No	is possible that a component that failed to be individually identified per R1.1 was included by entity A's maintenance plan. This documentation issue gets a higher VSL than entity B that identified a component without maintaining it. We suggest the R1 VSL be change to Low, since we believe lack of maintenance to be more severe than documentation issues.
Response: Thank you for your comments. The VSL for Requirement R1 addresses various levels of severity for degrees of non-compliance. The risk related to non-compliance with the various requirements is addressed by assignment of the associated VRFs. Additionally, Requirement R1 and the associated VSLs have been substantially modified, and may address your concern.		
Pepco Holdings, Inc. - Affiliates	No	It is possible that a component that failed to be individually identified per R1.1 was included by entity A's maintenance plan. This documentation issue gets a higher VSL than entity B that identified a component without maintaining it. We suggest the R1 VSL be change to Low, since we believe lack of maintenance to be more severe than documentation issues.
Response: Thank you for your comments. The VSL for Requirement R1 addresses various levels of severity for degrees of non-compliance.		
PNGC Power	No	It is possible that a component that failed to be individually identified per R1.1 was included by entity A's maintenance plan. This documentation issue gets a higher VSL than entity B that identified a component without maintaining it. We suggest the R1 VSL be change to Low, since we believe lack of maintenance to be more severe than documentation issues.
Response: Thank you for your comments. The VSL for Requirement R1 addresses various levels of severity for degrees of non-compliance.		
Long Island Power Authority	No	1. R4 under Severe VSL mentions - Entity has failed to initiate resolution of maintenance-correctable issues. What proofs will satisfy the requirement that the entity has initiated the resolution.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td></td><td></td><td>2. R1 under Severe VSL - LIPA suggests moving the first criteria “The entity’s PSMP failed to address one or more of the type of components included in the definition of “Protection System” under High VSL since this criteria cannot have the same VSL level as “Entity has not established a PSMP”.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. The SDT is unable to categorically state what will satisfy a Compliance Monitor, but it seems that a work order addressing the maintenance-correctable issue would be one example. FAQ IV.1.B and Section 15.7 of the Supplementary Reference Document may also be helpful.
2. The SDT believes that if an entity has missed one (of the five) entire component types in their program, they do not have a complete program.</td></tr>
<tr><td>Northeast Power Coordinating Council</td><td>No</td><td>1. R4 under Severe VSL mentions - Entity has failed to initiate resolution of maintenance-correctable issues. What proof will satisfy the requirement that the entity has initiated the resolution?
2. R1 under Severe VSL - Move the first criteria “The entity’s PSMP failed to address one or more of the type of components included in the definition of ‘Protection System’” under High VSL since this criteria cannot have the same VSL level as “Entity has not established a PSMP”.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. The SDT is unable to categorically state what will satisfy a Compliance Monitor, but it seems that a work order addressing the maintenance-correctable issue would be one example. FAQ IV.1.B and Section 15.7 of the Supplementary Reference Document may also be helpful.
2. The SDT believes that if an entity has missed one (of the five) entire component types in their program, they do not have a complete program.</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
MidAmerican Energy Company	No	The lower VSL specification for R4 should allow for a small level of incomplete testing. Suggest changing “5% or less” to “from 1% to 5%”.
Response: Thank you for your comments. The SDT shares your concerns regarding the Lower VSL portion of the stepped VSLs not providing any tolerance for non-conformance without being non-compliant. However, the VSL Guidelines, which conform to the FERC VSL Order, specify that Lower shall be “5% or less.”The VRF and VSLs are only a starting point in determining the size of a penalty or sanction – the Compliance Enforcement Authority has latitude to consider aggravating factors and mitigating factors in determining whether there should be any penalty, and the size of any penalty. These mitigating and aggravating factors are oultined in the Compliance Monitoring and Enforcement Program. http://www.nerc.com/files/Appendix4C_Uniform_CMEP_10022009.pdf		
Springfield Utility Board	No	The Violation Risk Factors are problematic. 1. With all due respect, it seems that NERC still operates in a "BIG UTILITY" mind set. Big utilities have potentially hundreds or thousands of components under different device types. Looking at the VRFs, the percentages 5% or 15% as an example, are looked at based on a deep pool of multiple devices so a "BIG UTILITY" that misses a component or small number of components may not trigger a high severity level. However a small utility may have only a handful of components under each type. Therefore if the small utility were to miss one component all of a sudden the utility automatically triggers the 5% or 15% threshold. This type of dynamic unreasonable and not equitable. Therefore (in an attempt to work within the framework proposed), SUB proposes that there be a minimum number of components that might not be in compliance which result in a much lower Violation Severity Level. SUB suggests that NERC try to create a level playing field. If 15% of a Big Utility's total number of components averages at around 15 out of 100 total then perhaps a reasonable outcome would be that up to 5 components (regardless of the total number of components an entity has under each type) could be in violation without tripping into a high VSL.(the 5 components threshold may not apply to all types, this is just for illustrative purposes).

Organization	Yes or No	Question 4 Comment
		2. Also, are the missed components compounding? For example, if an entity missed 5 components on year three and another 5 components in year 10 is the VSL based on 10 components or 5 components. There should be a time horizon attached to the VSL such that the VSL does not count prior components that were brought into compliance through a past action. That intent may be to not have the VSLs be based on compounding numbers of components; however that should be made clear.
Response: Thank you for your comments. You discussed VRFs, but it appears that you are actually discussing VSLs. 1. The SDT shares your concern about the stepped VSLs. However, the VSL Guidelines, developed in accordance with the FERC VSL Order, establish the Lower VSL for stepped VSLs as “5% or less,” the Medium VSL as “more than 5% but less than (or equal to) 10%,” the High VSL as “more than 10% up to (and including) 15%,” and the Severe VSL as “more than 15%.” The SDT did, however, modify the VSLs for R1 so that they do not use percentages. **2.** The VSLs are assigned on the basis of percentages of components for which you are non-compliant. The SDT suggests that you review the Compliance Monitoring Enforcement Program for clarification on self-reports, and so forth.		
Tennessee Valley Authority	No	The Violation Severity Level Table listing for Requirement R4 lists the following under “Severe VSL”.”Entity has failed to initiate resolution of maintenance-correctable issues” The threshold for a Severe Violation in this case is too broad and too subjective. The threshold needs to be clearly defined with low, medium, and high criteria.
Response: Thank you for your comments. The VSLs for Requirement R4 have been modified to provide stepped VSLs for initiation of resolution of maintenance-correctable issues.		
BGE	No	The VSL’s as proposed may be reasonable but it is difficult to endorse them until the ambiguity in R1.1 is reduced.
Response: Thank you.		
Duke Energy	No	The VSLs for PRC-005-2 requirements R1, R2 and R4 have significantly tighter

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td></td><td></td><td>percentages than the corresponding requirements in PRC-005-1. We believe that the Lower VSL should be up to 10%, the Moderate VSL should be 10%-15%, the High VSL should be 15% to 20%, and the Severe VSL should be greater than 20%, which is still a lower percentage than the 25% Lower VSL currently in PRC-005-1.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The SDT shares your concern abuout the stepped VSLs. However, the VSL Guidelines, developed in accordance with the FERC VSL Order, establish the Lower VSL for stepped VSLs as “5% or less,” the Medium VSL as “more than 5% but less than (or equal to) 10%,” the High VSL as “more than 10% up to (and including) 15%,” and the Severe VSL as “more than 15%.”</td></tr>
<tr><td>Indeck Energy Services</td><td>No</td><td>1. The VSL's treat all entities, components and problems alike. By combining 4 protection maintenance standards, it elevates the VSL on otherwise minor problems to the highest levels of any of the predecessor standards. The threshold percentages are very arbitrary. Severe VSL doesn't in any way relate to reliability. For a small generator to miss or mis-categorize 1 out of 7 relays is unlikely to have any impact on reliability, much less deserving a severe VSL. The R2 & R4 VSL's don't care about results of the program, only whether all components are covered. Half of the components could fail annually and it’s not a Severe VSL.
2. The R3 VSL allows 4% countable events, which can be hundreds for a large entity and only allows a few for a small entity.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. The VSL Guidelines, developed in accordance with the FERC VSL Order, establish the Lower VSL for stepped VSLs as “5% or less,” the Medium VSL as “more than 5% but less than (or equal to) 10%,” the High VSL as “more than 10% up to (and including) 15%,” and the Severe VSL as “more than 15%.” VSLs are not intended to assess the risk to reliability of noncompliance, VSLs are intended to identify different degrees of noncompliance with the associated requirement. The VRFs assess the risk to reliability of noncompliance with the requirement.
2. Relating to the R3 VSL, the “4% countable events” corresponds to the requirement relevant to performance-based programs in Attachment A. This value was determined to be a statistically significant value relating to performance-based programs, which</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
may not be practical for a small entity to implement without aggregation with other entities having similar programs. See Section 9 of the Supplementary Reference Document.		
US Bureau of Reclamation	No	1. The VSL's use terms that are not tied back to a requirement and appear to be based on the concept that every component will cause an impact on the BES. The VSL's use the term "countable event" to score the VSL; however, there is no requirement associated with the number of "countable events". 2. The VSL's should allow for minor gaps in maintenance documentation where there is no impact to the BES if the component failed.
Response: Thank you. 1. The VSL for Requirement R3, which you are questioning, addresses limits on “countable events” as they relate to the requirements for a Perfomance Based program within Attachment A. 2. The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation. The VRF and VSLs are only a starting point in determining the size of a penalty or sanction – the Compliance Enforcement Authority has latitude to consider aggravating factors and mitigating factors in determining whether there should be any penalty, and the size of any penalty. These mitigating and aggravating factors are oultined in the Compliance Monitoring and Enforcement Program. http://www.nerc.com/files/Appendix4C_Uniform_CMEP_10022009.pdf		
Black Hills Power	No	-VSL's are based on percentages of components, where the definition of a 'component' is in many cases up to the entity to interpret (see PRC-005-2 FAQ sheet, Page 2). Basing VSL's on an entities interpretation (or count) of 'components' is not an equitable measure of severity level.
Response: Thank you for your comment. A definition of “Component” has been added to the Standard to provide guidance and help provide consistency.		
JEA	No	We could find no rational provided for the % associated with each VSL, or component

Organization	Yes or No	Question 4 Comment
		rationale used to determine the proposed values listed. Is this included in some documentation that is available but not included as part of this review?
Response: Thank you for your comments. The percentages, are established in accordance with the VSL Guidelines, developed in accordance with the FERC VSL Order, which establish the Lower VSL for stepped VSLs as "5% or less," the Medium VSL as "more than 5% but less than (or equal to) 10%," the High VSL as "more than 10% up to (and including) 15%," and the Severe VSL as "more than 15%." The VSL Guidelines are posted on the Standard Resources web page: http://www.nerc.com/files/VSL_Guidelines_20090817.pdf		
American Electric Power	Yes	
American Transmission Company	Yes	
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	
Consumers Energy Company	Yes	
Dynegy Inc.	Yes	
Exelon	Yes	
FirstEnergy	Yes	
Great River Energy	Yes	

Organization	Yes or No	Question 4 Comment
Hydro One Networks	Yes	
MRO's NERC Standards Review Subcommittee (NSRS)	Yes	
Nebraska Public Power District	Yes	
PacifiCorp	Yes	
Public Service Enterprise Group ("PSEG Companies")	Yes	
ReliabilityFirst Corp.	Yes	
South Carolina Electric and Gas	Yes	
The United Illuminating Company	Yes	
We Energies	Yes	
Western Area Power Administration	Yes	
Y-W Electric Association,	Yes	

Organization	Yes or No	Question 4 Comment
Inc.		
MEAG Power	Yes	It would be good to have the basis of the 5%, 10% and 15% defined. With time and experience these percentages may need to be changed.
Response: Thank you for your comment. The VSL Guidelines, developed in accordance with the FERC VSL Order, establish the Lower VSL for stepped VSLs as “5% or less,” the Medium VSL as “more than 5% but less than (or equal to) 10%,” the High VSL as “more than 10% up to (and including) 15%,” and the Severe VSL as “more than 15%.”		
Manitoba Hydro	Yes	There is no rational provided for the % associated with each VSL, or component rationale used to determine the proposed values listed.
Response: Thank you for your comment. The VSL Guidelines, developed in accordance with the FERC VSL Order, establish the Lower VSL for stepped VSLs as “5% or less,” the Medium VSL as “more than 5% but less than (or equal to) 10%,” the High VSL as “more than 10% up to (and including) 15%,” and the Severe VSL as “more than 15%.”		

5. **The SDT has revised the "Supplementary Reference" document which is supplied to provide supporting discussion for the Requirements within the standard. Do you agree with the changes? If not, please provide specific suggestions for change.**

Summary Consideration: Most commenters seemed to appreciate the information provided within the Supplementary Reference document. Many commenters asked whether the Supplementary Reference was part of the Standard, to which the SDT replied, "No."

Several commenters also were concerned that the Supplementary Reference document may not be kept current with the Standard itself. There were assorted individual technical comments about the Supplementary Reference document, to which the SDT responded. Several comments irrelevant to the Supplementary Reference document were also offered; the SDT offered responses relevant to the comments.

Organization	Yes or No	Question 5 Comment
PPL Supply		No Comment.
Santee Cooper		No Comment.
SERC Protection and Control Sub-committee (PCS)		The SERC PCS expresses no opinion on this question.
San Diego Gas & Electric	No	
Ameren	No	1) Is this document considered part of the standard? We expect to use it as a reference in developing our PSMP, during audits, and for self-certification as an authentic source of information. It is also unclear how this document will be controlled (i.e. Revised and

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>Approved, if at all).
2) On page 22 please clarify that only applies to high speed ground switches associated with BES elements.
3) We appreciate the SDT providing this valuable reference.</td></tr>
<tr><td colspan="3">Response:Thank you for your comments.
1. This document provides supporting discussion, but is not part of the Standard. The SDT intends that it be posted as a reference document, accompanying the Standard. As established in SDT Guidelines, 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 document. The SDT intends that this document help explain, clarify, and in some cases suggest methods to comply with the Standard. The Standards Committee has a formal process for determining whether to authorize posting a reference document with an approved standard. That process is posted on the Standard Resources web page – here is a link to the procedure: http://www.nerc.com/files/SC_Process_Approve_Supporting_References_Approved_10Mar08.pdf
2. The Standard applies to High-Speed Ground Switches that are used to trip BES elements or that are used to protect BES elements. In response to your comment, the SDT has modifed the Supplementary Reference Section 15.3 as follows: “The SDT believes that this is essentially a transferred-tripping device without the use of communications equipment. If this high-speed ground switch is “…applied on, or designed to provide protection for the BES…” then this device needs to be treated as any other Protection System component. The control circuitry would have to be tested within 12 years and any electromechanically operated device will have to be tested every 6 years. If the spring-operated ground switch can be disconnected from the solenoid triggering unit then the solenoid triggering unit can easily be tested without the actual closing of the ground blade.
3. Thank you.</td></tr>
<tr><td>Xcel Energy</td><td>No</td><td>1. As we commented on in the previous draft of the standard that proposed the Supplementary Reference and FAQ, we are concerned as to what role these documents will play in compliance/auditing. It is also unclear how these documents will be controlled (i.e. Revised and Approved, if at all).
2. Inconsistencies have been identified between proposed standard and the documents</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
		(e.g. page 29 of FAQ example 1).
Response: Thank you for your comments. 1. This document provides supporting discussion, but is not part of the Standard. The SDT intends that it be posted as a Reference Document, accompanying the Standard. As established in SDT Guidelines, 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 document. The Supplementary Reference and FAQ have been revised to make them consistent with the new version of PRC-005-2. The Standards Committee has a formal process for determining whether to authorize posting a reference document with an approved standard. That process is posted on the Standard Resources web page – here is a link to the procedure: http://www.nerc.com/files/SC_Process_Approve_Supporting_References_Approved_10Mar08.pdf 2. Thank you. The FAQ has been revised to make it consistent with the new version of PRC-005-2 and the Supplementary Reference document.		
Pepco Holdings, Inc. - Affiliates	No	Figure 1 & 2 Legend (page 29), Row 5, Associated Communications Systems, includes Tele-protection equipment used to convey remote tripping action to a local trip coil or blocking signal to the trip logic (if applicable). This description does not include all the various types of signals communicated for proper operation of various protective schemes (i.e., DUTT, POTT, DCB, Current Differential, Phase Comparison, synchro-phasors, etc.) A more inclusive and generic description might be - Tele-protection equipment used to convey specific information, in the form of analog or digital signals, necessary for the correct operation of protective functions. This is also consistent with the revised definition of Protection System. Conversely, excluded equipment would be - Any communications equipment that is not used to convey information necessary for the correct operation of protective functions.
Response: Thank you for your comment. The Supplementary Reference and FAQ have been revised to make them consistent with the new version of PRC-005-2 and each other, and to incorporate language similar to your suggestion.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td>MEAG Power</td><td>No</td><td>Further clarification is needed. The information provided on verifying outputs of voltage and current sensing devices is confusing. In one part, it indicates that the intent is to verify that intended voltages and currents are getting to the relay apparently without regards to accuracy. A practical method of verifying the output of VTs and CTs is not identified and need to be identified.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.

The intent of the maintenance activity is to verify that the necessary values reach the protective relays. The SDT believes that a maintenance plan that requires infra-red scanning of VTs and CTs is not sufficient. The SDT further believes that routine commissioning tests, while certainly allowed, need not be required in the Standard because mere ratio tests would not prove that the values reach the relay.

A practical method is to read the values at the relays and, as you state, verify that the quantities meet your needs.

The SDT believes that the discussion in Section 15.2 of the Supplementary Reference is sufficient, and is supplemented in several subsections of FAQ II.3.</td></tr>
<tr><td>Indeck Energy Services</td><td>No</td><td>In 2.3, the applicability is stated to have been modified. As discussed at the FERC Technical Conference on Standards Development, the goal of the standards program is to avoid or prevent cascading outages--specifically not loss of load. The modified applicability moves away from the purpose of the standards program to an undefined fuzzy concept. Applicable Relays ignore the fact that some relays, or even some entities, have little to no affect on reliability. The global definition of Protective System encompasses all equipment, and doesn't differentiate the components that meet the purpose of the standards program. The Supplementary Reference doesn't overcome the inherent shortcomings of the standard.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.

The Supplementary Reference is intended to help clarify the Standard.</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
The United Illuminating Company	No	Include a detailed example of an Inventory list. Allow for different means of maintaining the lists electronically, that is, as spreadsheets, or databases.
Response: Thank you for your comments. The Supplementary Reference is intended to help clarify the Standard, not add to the Requirements of the Standard. Maintaining your lists is a business practice that you make, spreadsheets and/or databases have not been precluded in the Standard or in any reference document.		
US Bureau of Reclamation	No	It is not reasonable to assert that a statistical analysis of survey data is reliability based justification for requiring specific maintenance intervals. The reference document admits that intervals varied widely. To assert a postage stamp interval does not account for other variables which optimize a specific maintenance program. That is not saying that the reference documents are worthless. Indeed it has many good suggestions. However, to impugn the maintenance programs in practice because they do not follow the "weighted average" is hardly scientific or credible. The reference document should analyze the maintenance programs from the stand point of the outages associated with those facilities. If a specific maintenance practice was shown to have compromised the performance of the facility and the reliability of the BES, then it would added to the statistical database of practices which would not be acceptable. Now the statistical analysis of the database would show that certain practices have consequences which impact reliability and a requirement can be constructed to disallow them.
Response: Thank you for your comments. FERC directed the SDT to set maximum time intervals between maintenance activities. The SDT recognized that different types of equipment, different generations of equipment, different failure modes of equipment and different versions of time-based maintenance had to be considered. The SDT agrees with the commenter that the Standard allows statistical analysis and performance-based maintenance allows an entity to create time intervals that could exceed any "weighted-averages" time-based intervals. The Supplementary Reference adds a section (9) to show how an entity can create a performance-based maintenance interval.		

Organization	Yes or No	Question 5 Comment
Public Service Enterprise Group ("PSEG Companies")	No	1. Suggest that figure 2 has a line of demarcation added that shows components specifically not part of the standard requirements. (Medium voltage bus). 2. Battery charger should be removed from table of components when a storage battery is used for the DC supply.
Response: Thank you for your comments. 1. The figures are intended to be general information and not to be inclusive of all situations. **2.** The modification of the Protection System definition from "station battery" to "station dc supply" is intended to include battery chargers, and Table 1-4 within draft PRC-005-2 includes activities specifically related to battery chargers.		
JEA	No	The Supplementary Reference document is critical in our current compliance environment to be approved as part of the standard and any standard modifications need to be kept in synchronization with the FAQ and the Supplementary Reference.
Response: Thank you for your comments. **1.** This document provides supporting discussion, but is not part of the Standard. The SDT intends that it be posted as a reference document, accompanying the S. As established in SDT Guidelines, the Standard is to be a terse statement of requirements, etc., and is not to include explanatory information like that included in the FAQ and Supplementary Reference. The Supplementary Reference and FAQ have been revised to make them consistent with the new version of PRC-005-2.		
Long Island Power Authority	No	1. There is no guidance on how to calculate the total number of components and thus, the percentages under different severity levels. FAQ provides some insight into how an entity can count components however; an example in the reference document will provide clarity. 2. Page 7 of the redline version of Supplemental Reference - bullet 1 under Maintenance Services, paragraph 2, it says " If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>is reset for those components. LIPA believes that resetting the time clock will make tracking difficult (unless entities have a sophisticated automated tool for tracking). Another option where an entity can take credit for a correct performance within specifications at the time of the maintenance cycle should be included.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. A definition of “Component” has been added to the draft Standard to provide guidance. The Standard and the Tables have also been revised throughout for clarity.
2. The example cited is only offered as an option for entities that may wish to make use of observed real-time operations within their PSMP. An entity may, if desired, reset the time clock on a correct real-time occurrance. An entity does not have to “reset the time clock” if it chooses to maintain all of its components on a set schedule. The example given is merely one method to log a completed tripping action, which would alleviate the need to validate that same trip path. The SDT acknowledges that there are many ways to prove circuits; real-time switching or fault-clearing activities can be used but are not the only methods.</td></tr>
<tr><td>Northeast Power Coordinating Council</td><td>No</td><td>1. There is no guidance on how to calculate the total number of components and thus, the percentages under different severity levels. FAQ provides some insight into how an entity can count components.
2. However; an example in the reference document will provide clarity. Page 7 of the redline version of Supplemental Reference - bullet 1 under Maintenance Services, paragraph 2 states “ If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock is reset for those components.” Resetting the time clock will make tracking difficult (unless entities have a sophisticated automated tool for tracking). Another option where an entity can take credit for a correct performance within specifications at the time of the maintenance cycle should be included.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. A definition of “Component” has been added to the draft Standard to provide guidance. The Standard and the Tables have also</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
been revised throughout for clarity. **2.** The example cited is only offered as an option for entities that may wish to make use of observed real-time operations within their PSMP. An entity may, if desired, reset the time clock on a correct real-time occurrance. An entity does not have to “reset the time clock” if it chooses to maintain all of its components on a set schedule. The example given is merely one method to log a completed tripping action, which would alleviate the need to validate that same trip path. The SDT acknowledges that there are many ways to prove circuits; real-time switching or fault-clearing activities can be used but are not the only methods.		
Northeast Utilities	No	There is no guidance on how to calculate the total number of components and thus, the percentages under different severity levels. FAQ provides some insight into how an entity can count components however; an example in the reference document will provide clarity.
Response: Thank you for your comments. A definition of “Component” has been added to the draft Standard to provide guidance. The Standard and the Tables have also been revised throughout for clarity.		
Tennessee Valley Authority	No	1. There needs to be a defined method of deferral when equipment can’t be gotten out of service until a scheduled outage. 2. Give some examples of what “inputs and outputs that are essential to proper functioning of the Protection System” are. 3. a) Define what a “Control and Trip Circuit” is. 4. b) Is there one per relay? 5. c) Do I have to have a list of them in my work management system?
Response: Thank you for your comments. 1. “Grace periods” within the Standard are not measurable, and could lead to persistently increasing intervals. 2. Some examples of outputs may include but are not limited to: trip, initiate zone timer, initiate breaker fail. Some examples of input may include but are not limited to: breaker fail initiate, start timer. This cannot be an all-inclusive list as any given scheme could have many variations. In short, if your scheme requires a specific input to function properly then you must have that input		

Organization	Yes or No	Question 5 Comment
maintained; if your scheme has a specific output that must function then it must be maintained. If the input or output is used for a non-protective function (such as, but not limited to, Sequence-of-Events Recorder, alarm or indication) then it does not have to be maintained under this Standard. See Section 15.3 of the Supplementary Reference and FAQ II.2.L. 3. a) Circuitry needed for the correct operation of the protective relay. A definition of "Component" has been added to the draft Standard to provide guidance. See Section Section 15.3 of the Supplementary Reference. 4. b) This depends on your scheme and your relay. A definition of "Component" has been added to the draft Standard to provide guidance. **5.** c) The SDT believes that a PSMP that requires maintenance upon all of the circuits, and includes a check-off (list) system that accounts for all circuits being verified would suffice.		
American Electric Power	Yes	
American Transmission Company	Yes	
Arizona Public Service Company	Yes	
BGE	Yes	
Black Hills Power	Yes	
Constellation Power Generation	Yes	
Consumers Energy Company	Yes	

Organization	Yes or No	Question 5 Comment
Duke Energy	Yes	
Dynegy Inc.	Yes	
Entergy Services	Yes	
Exelon	Yes	
Great River Energy	Yes	
Hydro One Networks	Yes	
Manitoba Hydro	Yes	
MidAmerican Energy Company	Yes	
MRO’s NERC Standards Review Subcommittee (NSRS)	Yes	
NERC Staff	Yes	
Pacific Northwest Small Public Power Utility Comment Group	Yes	
PacifiCorp	Yes	

Organization	Yes or No	Question 5 Comment
PNGC Power	Yes	
Progress Energy Carolinas	Yes	
ReliabilityFirst Corp.	Yes	
South Carolina Electric and Gas	Yes	
Southern Company Transmission	Yes	
The Detroit Edison Company	Yes	
We Energies	Yes	
Western Area Power Administration	Yes	
Y-W Electric Association, Inc.	Yes	
WECC	Yes	Compliance does agree with the clarity and the Supplementary Reference should be specially referenced where appropriate the Tables 1a, 1b, 1c and Attachment A that are included with the Standard. But this reference is not a part of the approved standard and there are no controls which prevent changes in the reference document that could impact the scope or intent of the standard. If the standard is approved with reference to the Supplementary Reference then future changes to the Supplementary Reference should not be allowed without due process. Only the version in existence at the time of approval of the

Organization	Yes or No	Question 5 Comment
		standard could be used to clarify or explain the standard.
Response: Thank you for your comments. The SDT intends that the Supplementary Reference document be updated as the Standard is revised to maintain its relevance to the application of the Standard. The Standards Committee has a formal process for determining whether to authorize posting a reference document with an approved standard. That process is posted on the Standard Resources web page – here is a link to the procedure: http://www.nerc.com/files/SC_Process_Approve_Supporting_References_Approved_10Mar08.pdf		
Nebraska Public Power District	Yes	Is this document considered part of the standard and may be referenced during audit and self-certification as an authentic source of information?
Response: Thank you for your comments. This document provides supporting discussion, but is not part of the Standard. The SDT intends that these be posted as reference documents, accompanying the Standard. The Standards Committee has a formal process for determining whether to authorize posting a reference document with an approved standard. That process is posted on the Standard Resources web page – here is a link to the procedure: http://www.nerc.com/files/SC_Process_Approve_Supporting_References_Approved_10Mar08.pdf		
Springfield Utility Board	Yes	SUB appreciates that Time Based, Performance Based, and Condition Based programs can be combined into one program. However it should be clear that a utility may include one, two or all three of these types of programs for each individual device type. Currently the language reads:"TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System." The "and" requires all three to be combined if they are combined. SUB suggests the “and” be changed to "or". Language Change: "TBM, PBM, or CBM can be combined for individual components, or within a complete Protection System."
Response: Thank you for your comments. The SDT modified Requirement R1 of the Standard.		
FirstEnergy	Yes	We support the reference document and appreciate the SDT's hard work developing this

Organization	Yes or No	Question 5 Comment
		document. We offer the following suggestions for possible improvements: 1. The reference document should be linked in Section F of the standard. Otherwise it may be difficult for someone to navigate the NERC website in search of the document. 2. Section 2.2 - It would be helpful if a short discussion of the reasons for the changes to the definition of Protection System was included in this reference document. In addition, it would be beneficial to discuss what is included in "dc supply" components, such as "dc supplies include battery chargers which are required to be maintained per the Tables in PRC-005-2." 3. Section 8.1 - The fourth bullet which reads "If your PSMP (plan) requires more then you must document more." Should be removed. This is already covered in the sixth bullet which states "If your PSMP (plan) requires activities more often than the Tables maximum then you must document those activities more often."

Response: Thank you for your comments.

1. This issue may be a good idea. The Standards Committee has a formal process for determining whether to authorize posting a reference document with an approved standard. That process is posted on the Standard Resources web page – here is a link to the procedure: http://www.nerc.com/files/SC_Process_Approve_Supporting_References_Approved_10Mar08.pdf.
2. The reasons for the definition change are transitory and should not be in the Supplementary Reference document. The reasons may be found in the SAR for Project 2007-17. See Section 15.4 of the Supplementary Reference for discussion about batteries and dc supply.
3. The SDT disagrees with your assertion. The first cited example applies to the activities within your program, and the second applies to the intervals. These are related but separate. The fourth bullet in Section 8.1 has been revised to clarify.

6. The SDT has revised the "Frequently-Asked Questions" (FAQ) document which is supplied to address anticipated questions relative to the standard. Do you agree with these changes? If not, please provide specific suggestions for change.

Summary Consideration: Most commenters seemed to appreciate the information provided within the FAQ document. Many commenters asked whether the FAQ was part of the Standard, to which the SDT replied, "No." Several commenters also were concerned that the FAQ document may not be kept current with the Standard itself. There were assorted individual technical comments about the FAQ, to which the SDT responded. Several comments irrelevant to the FAQ were also offered; the SDT offered responses relevant to the comments.

Organization	Yes or No	Question 6 Comment
MEAG Power		No comment.
PPL Supply		No Comment.
Santee Cooper		No comment.
SERC Protection and Control Sub-committee (PCS)		The SERC PCS expresses no opinion on this question.
Indeck Energy Services	No	
San Diego Gas & Electric	No	
Consumers Energy	No	1. FAQ II.3A attempts to clarify the requirements of "Verify the proper functioning of the current and voltage signals necessary for Protection System operation from the voltage

Organization	Yes or No	Question 6 Comment
Company		and current sensing devices to the protective relays" suggesting that "simplicity can be achieved" by verifying that the protective relays are receiving "expected values." It concludes with a statement of the need to "ensure that all of the individual components are functioning properly ..." implying that just verifying "expected values" at the protective relay end of the circuit may be inadequate. 2. FAQ II.4D describes what is required for testing of aux relays to include, "that their trip output(s) perform as expected". Does that include timing tests? (Example - high speed ABB AR relays vs. standard AR relays). 3. The SDT responses to the Draft 1 comments regarding "grace periods" essentially says, "Absolutely not". However, FAQ IV.1.D reflects data retention requirements relative to an entities' program which includes a grace period!

Response: Thank you for your comments.

1. "Expected values" was intended to convey that the current and/or voltage sensing devices were functioning properly. The SDT intentionally left out any Requirement in the Standard that the values being read at the protective relays be within a specific tolerance because each entity may have valid rationale for tolerances at any level. To find a current or voltage value that is wrong would indicate that something in the voltage or current secondary delivery system is not functioning properly and needs corrective action. Typically an entity can review values measured at the relay and determine that the values are as expected and that the maintenance activity has been satisfied.
2. If an entity has designed a protection scheme which contains parts that need to function in a specific manner then those parts need to be routinely maintained to assure that they perform at that level. The SDT believes that Protection Systems exist at all levels of complexity and that some systems will be easier to test than others, but that all components that are necessary for the proper functioning of the Protection System must be maintained. In short, if an entity decided that specific parts were necessary for the proper operation of the Protection System then those parts need to be routinely maintained.
3. There is no "grace period" allowed by the Standard; a "grace period" is not measurable. That means that the intervals between the specified maintenance activities in the Standard cannot exceed those established within the Tables. However, many entities have built in "allowable extensions" to their intervals (thus creating "grace periods" within their own PSMP). In these particular PSMP's the total time allowed between the specified maintenance activities (including any allowable extensions or "grace periods") does not

Organization	Yes or No	Question 6 Comment
exceed the maximum allowed time interval established in the Standard. For example, an entity has in their PSMP that "…the electro-mechanical relays will be tested every 3 calendar years with a maximum allowable extension of 18 additional calendar months to allow for scheduling difficulties and unplanned emergencies." In this way the entity will be audited to their PSMP, they have added 50% time in the form of their own grace period and the maximum time between the specified maintenance activities does not exceed the time interval established in the Standard. Also see FAQ IV.2.H for additional discussion on this.		
Xcel Energy	No	1. As we commented on in the previous draft of the standard that proposed the Supplementary Reference and FAQ, we are concerned as to what role these documents will play in compliance/auditing. It is also unclear how these documents will be controlled (i.e. Revised and approved, if at all). 2. Inconsistencies have been identified between proposed standard and the documents (e.g. page 29 of FAQ example 1).
Response: Thank you for your comments. **1.** This document provides supporting discussion, but is not part of the Standard. The SDT intends that it be posted as a reference document, accompanying the Standard. As established in SDT Guidelines, 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 document. The FAQ and the Supplementary Reference documents have been revised to make them consistent with the new version of PRC-005-2. 1. The Standards Committee has a formal process for determining whether to authorize posting a reference document with an approved standard. That process is posted on the Standard Resources web page – here is a link to the procedure: http://www.nerc.com/files/SC_Process_Approve_Supporting_References_Approved_10Mar08.pdf **2.** Thank you. The FAQ has been revised to be consistent with the new version of the Standard.		
Nebraska Public Power District	No	1. FAQ 2.G, page 24 - NPPD believes system reliability will be decreased if an entity is considered non-compliant for exceeding a PSMP stated interval that is within the PRC-005-2 Maximum Maintenance Interval. Considering an entity non-compliant for such a situation will encourage establishment of intervals that only meet the minimum standard. There should be one standard interval that all entities must be monitored against. If an entity wants to perform maintenance more frequently, it should not be subject to non-

Organization	Yes or No	Question 6 Comment
		compliance if it misses its target but meets the Maximum Maintenance Interval in the standard. 2. There are definitions at the beginning of the FAQ that should be contained in the NERC definitions and not in an FAQ. Placing these in an approved definition will help avoid interpretation issues that would arise during future audits.
Response: Thank you for your comments. 1. The SDT believes that there are many reasons that would prompt an entity to have some intervals that are more frequent than those intervals established in the Standard (performance-based maintenance is but a single example). If an entity chooses to perform maintenance more often than the limits set within the Standard then it may do so. If an entity chooses to perform maintenance more often than the limits set within its own PSMP then it may do so. **2.** The SDT desires to conform to certain rules regarding this issue. If a term appears in the NERC Glossary then all Standards will have to conform to the definition established. If the terms are shown elsewhere, in the FAQ for example, then clarity can be achieved when the Standard is read. The SDT intends to help clarify by creating the two supporting reference documents, but not to restrict other Standards to the uses of some words that will inevitably be shared amongst Standards. The SDT has also moved several of these definitions to the Standard with the intent that they be part of only this Standard and not a general definition within the NERC Glossary of Terms.		
Progress Energy Carolinas	No	1. FAQ II.2.A: What degree of testing is required for a relay firmware upgrade? Complete commissioning tests? 2. FAQ V.1.A. There appears to be a typo in Example #1 for “Vented lead-acid battery with low voltage alarm connected to SCADA (level 2)”: Table 1b does not list any level 2 requirements. Rather, the table refers reader back to the Level 1 requirements. Same comment for Example #2 as well. 3. FAQ III.1.A: Project 2009-17 provides a response to a request for interpretation of the term “transmission Protection System” as related to PRC-004-1 and PRC-005-1. The interpretation addresses the boundaries of the transmission system. NERC should

Organization	Yes or No	Question 6 Comment
		investigate whether this same boundary should be defined within the new PRC-005-2. 4. Also, numerous potential boundary issues exist between entities which should be contemplated and addressed. See the examples below: a) Utility A may own equipment in Utility B's substation. Utility A contracts Utility B to perform maintenance on their equipment. However, the two utilities have different maintenance programs and intervals for the same types of equipment. Who is responsible for NERC compliance? Would Utility A be found in violation because their equipment is being maintained under Utility B's program which deviates from Utility A's maintenance basis? b) EMC protection is fed from a utility's instrument transformers. Who is responsible for validation of the relay inputs and testing of the instrument transformers? c) Utility-owned communication units (used for transfer trip or carrier blocking) are coupled to the utility's power line using customer-owned CCVTs. Who is responsible for maintenance and testing of these CCVTs? d) Utility A owns all equipment at one end of line (line terminal A) and Utility B owns all equipment at other end of line (line terminal B). Who is responsible for demonstrating the carrier blocking scheme or POTT scheme works correctly?

Response: Thank you for your comments.

1. Complete commissioning tests can be required by the entity. Commissioning tests are not specified within the Standard. The status of the relay should be that it is ready for use after the firmware upgrade. If the maintenance activities were performed that are specified within the Standard and its PSMP, then the entity may choose to reset the time clock for maintenance for that device.
2. The Tables within the Standard have been completely revised, and the FAQ revised to align.
3. When the interpretation (Project 2009-17) is approved, the SDT for PRC-005-2 will consider if the interpretation is appropriate for PRC-005-2 and make associated changes.

   a) The owner of the equipment is responsible for assuring that the equipment is maintained according to its PSMP. This is

Organization	Yes or No	Question 6 Comment
consistent with the concepts in the Functional Model. b) The owner of the equipment is responsible for assuring that the equipment is maintained according to its PSMP. c) The owner of the equipment is responsible for assuring that the equipment is maintained according to its PSMP. d) The owner of the equipment is responsible for assuring that the equipment is maintained according to its PSMP. The entities should coordinate on equipment that affects each other to assure that the equipment is tested in such a fashion that it complies with both entities' PSMP.		
Tennessee Valley Authority	No	If a relay is tested during a generator outage, what date is allowed to be used for compliance - actual test date or date equipment was returned to service? These are usually only a few weeks apart, but may be as much as three months different.
Response: Thank you for your comments. An entity's own records are used to judge compliance. The date placed on the evidence should be the date on which testing of the relevant Protection System component is completed.		
Northeast Utilities	No	Page 2 under Component definition, term "somewhat arbitrary" is used by the drafting team to address what constitutes a dc control circuit. Though the drafting team has provided entities with flexibility to define as per their methodologies, it is recommended to clearly determine "what constitutes a dc control circuit" since it will be used to determine compliance.
Response: Thank you for your comments. The SDT believes that if the circuit is needed for the Protection System to operate or function correctly, then that circuit must be maintained.		
South Carolina Electric and Gas	No	Question/Answer 4-C (Pg. 10 of FAQ) seems to indicate that by documenting breaker operations for fault conditions the table 1b requirements for control circuitry (Trip Coils and Auxiliary relays) can be satisfied. It is possible that even though a breaker successfully

Organization	Yes or No	Question 6 Comment
		operates for a fault condition one trip coil of a primary/backup design can be inoperable and “masked” by the good trip coil. Although it is likely that a faulty trip coil would be caught by monitoring of continuity it is not a certainty that both trip coils actually operated to clear a fault (example-mechanical binding)
Response: Thank you for your comments. The SDT agrees. While a successful trip operation can fulfill requirements of the Standard, it is useful only for the trip paths for which successful operation was demonstrated and documented.		
BGE	No	The FAQ is a very helpful document. A few more changes would be beneficial. See comments regarding manufactures’ advisories and R1.1 under section 7 below. It is our recommendation that manufacturers service advisories not be an implied part of the PMSP requirements and that the expectations for R1.1 be more explicitly described in the FAQ.
Response: Thank you for your comments. The Supplementary Reference and the FAQ are not a part of the Standard. The intent of the SDT is that the documents help provide clarity, not to imply additional maintenance. The required minimum maintenance activities are listed in the Standard. Requirement R1 and the tables have been extensively revised.		
American Transmission Company	No	The FAQs are helpful, however, with the revised standard as written; ATC has issues with the answers provided. Please refer to Question #7 for areas of concern.
Response: Thank you for your comments. The Standard and the Tables have been revised to add clarity. The FAQ and the Supplementary Reference documents have been revised to make them consistent with the new version of PRC-005-2. Please see our responses to your comments in Question 7.		
MRO’s NERC Standards Review Subcommittee	No	The FAQs are helpful, however, with the revised standard as written, The NSRS has issues with the answers provided. Please refer to Question #7 for areas of concern.

Organization	Yes or No	Question 6 Comment
(NSRS)		
Response: Thank you for your comments. The Standard and the tables have been revised to improve clarity. The FAQ and the Supplementary Reference documents have been revised to make them consistent with the new version of PRC-005-2. Please see our responses to your comments in Question 7.		
Constellation Power Generation	No	The PT/CT testing section is implying that the testing must be completed while energized, which is counter to industry practice at generation facilities. Leeway should be given to the entities to devise their own methods for testing voltage and current sensing devices and wiring to the protection system.
Response: Thank you for your comments. The required minimum maintenance activities are listed in the Standard. The intent of the cited section is to provide examples of how an entity <u>might</u> perform the testing. Any examples listed in either of the supporting documents should be looked upon as suggestions; these suggestions are not considered to be a complete list of the methods available. To the contrary, the Standard and the supporting documents were written considering that there are many ways to achieve a good test. Leeway is certainly available in how an entity complies with the Standard as the maintenance activities generally specify “what” must be achieved but not “how” an entity achieves it. Please see FAQ II.3.D.		
Pepco Holdings, Inc. - Affiliates	No	1. The three month inspection interval for communication equipment mentioned in FAQ II 6 B should be extended to 12 - 18 months (see response to Question #1). 2. In addition, the example used in this section should address what is expected for ON-OFF carrier systems. Checking that the equipment is free from alarms and still powered up does not seem sufficient to verify functionality. The FAQ states that the concept should be that the entity verifies that the communication equipment...is operable through a cursory inspection and site visit. However, unlike FSK schemes where channel integrity can easily be verified by the presence of a guard signal, ON-OFF carrier schemes would require a check-back or loop-back test be initiated to verify channel integrity. If the carrier set was not equipped with this feature, verification would

Organization	Yes or No	Question 6 Comment
		require personnel to be dispatched to each terminal to perform these manual checks.
Response: Thank you for your comments. 1. The SDT believes that the 3-month interval is proper for unmonitored communications systems. **2.** As you suggest, this funcitionality would normally be verified by a manual or automatic checkback system, and, even then, a station visit would be necessary if alarms are not provided. Where such equipment is not available, a station visit would be necessary.		
Public Service Enterprise Group ("PSEG Companies")	No	This is a very useful document and provides a good source of additional information; there are some cases where it could be interpreted as a standard requirement that can lead to confusion if conflicts exist. For example, the group by monitoring level example V.1.A shown on page 29 describes a level 2 partial monitoring as circuits alerting a 24Hr staffed operations center, page 38 shows level 2 monitoring as detected issues are reported daily. The actual standard table 1b level 2 monitor describes alarms are automatically provided daily to a location where action can be taken for alarmed failures within 1 day or less. This is listed as a supplemental reference document in the standard. The FAQ document "supports" the standard but is or is not an official interpretation tool, or if it is state as such.
Response: Thank you for your comments. The FAQ provides supporting discussion, but is not part of the Standard. The SDT intends that it be posted as a reference document, accompanying the Standard. As established in SDT Guidelines, the Standard is to be a terse statement of requirements, etc., and is not to include explanatory information like that included in the FAQ.		
The United Illuminating Company	No	What actions are taken if the owner can not perform a specific activity elaborated on the tables due to the design of the equipment? Is the owner in non-compliance? Must the owner only accept equipment solutions that allow the maintenance activities elaborated in the standard to be performed?

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comments. The SDT is not aware of any activities that cannot be performed as you cite.		
JEA	No	Yes the FAQ is also a very important document to be approved along with the standard. There must be a way to have the standard and the FAQ go hand-in-hand or the standard must be revised to include much of the FAQ.
Response: Thank you for your comments. The FAQ provides supporting discussion, but is not part of the Standard. The SDT intends that it be posted as a reference document, accompanying the Standard. As established in SDT Guidelines, 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 the FAQ. The FAQ and the Supplementary Reference documents have been revised to make them consistent with the new version of PRC-005-2. The Standards Committee has a formal process for determining whether to authorize posting a reference document with an approved standard. That process is posted on the Standard Resources web page – here is a link to the procedure: http://www.nerc.com/files/SC_Process_Approve_Supporting_References_Approved_10Mar08.pdf		
American Electric Power	Yes	
Arizona Public Service Company	Yes	
Black Hills Power	Yes	
Duke Energy	Yes	
Dynegy Inc.	Yes	

Organization	Yes or No	Question 6 Comment
Entergy Services	Yes	
Exelon	Yes	
Great River Energy	Yes	
Hydro One Networks	Yes	
Long Island Power Authority	Yes	
Manitoba Hydro	Yes	
MidAmerican Energy Company	Yes	
NERC Staff	Yes	
Northeast Power Coordinating Council	Yes	
Pacific Northwest Small Public Power Utility Comment Group	Yes	
PacifiCorp	Yes	
PNGC Power	Yes	

Organization	Yes or No	Question 6 Comment
ReliabilityFirst Corp.	Yes	
Southern Company Transmission	Yes	
Springfield Utility Board	Yes	
The Detroit Edison Company	Yes	
We Energies	Yes	
Y-W Electric Association, Inc.	Yes	
Ameren	Yes	1) Is this document considered part of the standard? We expect to use it as a reference in developing our PSMP, during audits, and for self-certification as an authentic source of information. It is also unclear how this document will be controlled (i.e. Revised and Approved, if at all). 2) The FAQ needs to be aligned with the tables. The FAQ also contains a duplicate decision tree chart for DC Supply. The FAQ contains a note on the Decision tree that reads, "Note: Physical inspection of the battery is required regardless of level of monitoring used", this statement should be placed on the table itself, and should include the word quarterly to define the inspection period. 3) We appreciate the SDT providing this valuable reference.

Response: Response: Thank you for your comments.

1. The FAQ provides supporting discussion, but is not part of the Standard. The SDT intends that it be posted as a reference document,

Organization	Yes or No	Question 6 Comment
accompanying the Standard. As established in SDT Guidelines, 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 the FAQ. The FAQ and the Supplementary Reference documents have been revised to make them consistent with the new version of PRC-005-2. The Standards Committee has a formal process for determining whether to authorize posting a reference document with an approved standard. That process is posted on the Standard Resources web page – here is a link to the procedure: http://www.nerc.com/files/SC_Process_Approve_Supporting_References_Approved_10Mar08.pdf 2. The FAQ has been revised to make it consistent with the new version of PRC-005-2. The decision trees were removed. 3. Thank you.		
Western Area Power Administration	Yes	Clarification 1) FAQ, page 36, Control Circuit Monitor Level Decision Tree: It's not clear if the note on Level 1 device operation is required for Level 3 monitoring.
Response: Thank you for your comments. The Standard and Tables have been extensively revised. The FAQ has been revised to make it consistent with the new version of PRC-005-2. The decision trees were removed from the FAQ.		
WECC	Yes	Compliance does agree with the clarity. The FAQ answers should be referenced specifically to the Standard and the Supplementary Reference to further understand those two documents. However, endorsement of the Standard should not imply endorsement of the FAQ and vice versa.
Response: Thank you for your comments.		
FirstEnergy	Yes	We support the FAQ document and appreciate the SDT's hard work developing this document. The reference document should be linked in Section F of the standard. Otherwise it may be difficult for someone to navigate the NERC website in search of the document.
4. **Response:** Thank you for your comments. The Standards Committee has a formal process for determining whether to authorize		

Organization	Yes or No	Question 6 Comment
posting a reference document with an approved standard. That process is posted on the Standard Resources web page – here is a link to the procedure: http://www.nerc.com/files/SC_Process_Approve_Supporting_References_Approved_10Mar08.pdf If approved as a permanent reference to a standard, then on the "Reliability Standard" web page, there will be a link (in the same cell as the link to the standard and its archive) to any reference documents approved for posting with the standard.		

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

Summary Consideration: Comments were offered on virtually every aspect of the draft Standard. Many of these comments resulted in changes to the Standard. The Tables were commented on heavily, and they were completely revised in response. Many commenters were concerned about not having provision for a "grace period," and the SDT responded that this was not allowable. "100% compliance" was also a concern, and the SDT responded that there was not a means of permitting some level of non-conformance without being also non-compliant.

Organization	Question 7 Comment
GDS Associates	Definition of Terms Used in the Standard. Protection System Maintenance Program 1. Monitoring. Concerned about the interpretation of this activity description 2. Upkeep. Not sure about how this activity will be enforced – A. Introduction. 4.2. Facilities. 3. The applicability does not address the current issues regarding radial + load serving only situation when Protection System not designed to provide protection for the BES. Standard should clearly state this exemption. B. Requirements. 4. 1.1. The standard does not provide guidance in how to identify the components of a transmission Protection System (tPS). See prior comment referring to the case of a radial load serving transmission topology. 5. 1.3. Requirement should read "For each identified Protection System component from Requirement 1, part 1.1, include all maintenance activities listed in PSMP and specified in Tables 1a, 1b, or 1c associated with the maintenance method used per

Organization	Question 7 Comment
	Requirement 1, part 1.2." 6. 1.4. This requirement should be eliminated since already included in Table 1a and covered through Requirement 1, part 1.3. 7. 4.3. Footnote 3 shall be eliminated since duplicates footnote 2 – C. Measures 8. M1. The added wording in the Protection System definition, requirements and measures with respect to the inclusion of the "associated circuitry from the voltage and current sensing devices" and control circuitry "through the trip coil(s) of the circuit breakers or other interrupting devices" seem right but a bit excessive under current circumstances (form of the standard). The standard should clearly specify how the maintenance program will address the verification, monitoring, etc. of the actual wiring and the trip coils. We suggest that the wording of the standard to reflect that the maintenance activities on the wiring will be conducted in a visual fashion without implying activities that require disconnecting the primary equipment. 9. We recommend to change the Protection System definition to read "up to the trip coils(s)" instead the word "through" (see comment on the definition as well). We consider that the gain in reliability by pursuing a thorough maintenance program that require to take primary equipment out of service (which in many instances will lead to the entire substation being put out of service) cannot counterweight the sole purpose of the standard and the economics emerging from this program.

Response: Thank you for your comments.

1. The SDT is unable to determine the nature of your concern. "Monitoring" is used within PRC-005-2 only as discussed in the new Table 2.
2. The SDT has removed "Upkeep" from the PSMP definition in response to your comment.
3. This is an issue for your regional BES definition.

Organization	Question 7 Comment
4. The SDT has extensively revised Requirement R1 and its sub-requirements. 5. The SDT has extensively revised Requirement R1 and its sub-requirements. 6. The SDT has removed Requirement R1, part 1.4, in consideration of your comment. 7. The footnotes have been removed. 8. The SDT is not specifying the means of achieving requirements. This allows entities the flexibility to determine their own optimal methods. 9. The SDT considers that the electrical trip coils are an integral portion of the dc control circuit, and therefore must be exercised.	
Western Area Power Administration	1) Standard, Page 4, R 4.3: Is the utility free to define its own “acceptable limits”? 2) Standard, Page 4, R 4.3: Must the “acceptable limits” be stated in the PSMP? 3) Standard, Page 4, Footnotes 2 and 3 are the same. 4) Attachment A says we can go to a performance based program; does this apply to every part of the standard? In other words, does this apply to component testing, functional testing, etc., and do we define the intervals of the test. That is, do we determine how long we test the sample of at least 30 units that Attachment A discusses?
Response: Thank you for your comments. 1. As “acceptable limits” may vary with the specific application, the entity is expected to determine appropriate acceptable limits. 2. There is no requirement within the draft Standard for an entity to specify the acceptable limits within its own PSMP. 3. The footnotes have been removed. 4. The draft Standard allows entities to implement a performance-based program for all component types except batteries if they have appropriate populations. Attachment A specifies that the entity “Maintain the components in each segment according to the time-based maximum allowable intervals established in Tables 1-1through 1-5 until results of maintenance activities for the segment are available for a minimum of 30 individual components of the segment.” After that period, the entity may shift to the performance-based program for the entire segment.	

Organization	Question 7 Comment
Ameren	1) We commend the SDT for developing a generally clear and well documented second draft. The SDT considered and adopted many industry comments from the first draft. It generally provides a well reasoned and balanced view of Protection System Maintenance, and good justification for its maximum intervals. Ameren generally agrees that this second draft will be beneficial to BES reliability, but several inconsistencies, unclear items, and a couple issues need to be addressed before we will be able to support it. 2) Facilities Section 4.2.1 “or designed to provide protection for the BES” needs to be clarified so that it incorporates the latest Project 2009-17 interpretation. The industry has deliberated and reached a conclusion that provides a meaningful and appropriate border for the transmission Protection System; this needs to be acknowledged in PRC-005-2 and carried forward. 3) We are concerned over R1.1, where all components must be identified, without a definition for the word component or the granularity specified. While the FAQ gives a definition, and allows for entity latitude in determining the granularity, the FAQ is not part of the standard. Certainly this could confuse an entity or an auditor and lead to much wasted work and / or violations for unintended or insignificant issues. We suggest that the FAQ definitions be included within the standard. 4) Implementation of the PSMP must coincide with the beginning of a calendar year. 5) Generating Plant system-connected Station Service transformers should not be included as a Facility because they are serving load. Omit 4.2.5.5 from the standard. There is no difference between a station service transformer and a transformer serving load on the distribution system. This has no impact on the BES, which is defined as the system greater than 100 kV. 6) The term “maintenance correctable issue” used in Requirement 4 seems to be at odds with the definition given for it. It seems that an issue that cannot be resolved by repair or calibration during the maintenance activity would be a maintenance non-correctable issue. Also, in Requirement 4, the term “identification of the resolution” is ambiguous. Suggested changes for Requirements 4 and 4.1 are: “R4. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement its PSMP, and resolve any performance problems as follows: 4.3 Ensure either that the components are within acceptable parameters at the conclusion of the maintenance activities or initiate actions to replace the component or restore its performance to within acceptable parameters.”

Organization	Question 7 Comment
Response: Thank you for your comments. 1. Thank you. 2. When the interpretation (Project 2009-17) is approved, the SDT for PRC-005-2 will consider if the interpretation is appropriate for PRC-005-2 and make associated changes. 3. Requirement R1 has been extensively revised, and the SDT has added a definition of "Component" and "Component Type" to the draft Standard. The SDT's intent is that this definition will be used only in PRC-005-2, and thus will remain with the Standard when approved, rather than being relocated to the Glossary of Terms. 4. The SDT Guidelines, which were endorsed by the NERC Standards Committee in April 2009, establishes that proposed effective dates "must be the first day of the first calendar quarter after entities are expected to be compliant." The Implementation Plan is in accordance with these guidelines. 5. The "load" being served by the station service transformer may be essential to operation of the generating plant, and therefore is not the same as general distribution system load. Therefore, the SDT believes that these system components must remain within the Applicability section of the Standard. 6. The definition of "maintenance correctable issue" is consistent with the way it is used within the Standard.	
PPL Supply	1. For applicability to generators, the responsibility for a maintenance program will usually rest with the plant operator when the operator and plant owner(s) are different entities. Consider changing the applicability as it applies to the generator in such situations. 2. Time-based frequency should allow for flexibility; i.e. engineering analysis should allow the entity to exceed the intervals noted in the table. An engineering evaluation that defines a test interval differently than those intervals prescribed in the table should allow an entity to build a program with different intervals. 3. A Grace Period should be defined. This allows a tolerance window to allow for unforeseen occurrences. A grace period would allow for some schedule flexibility and reduce the number of reports to the regulator for exceeding an interval by a reasonable about. 4. The implementation plan for this revision should take into account that a generator outage may be

Organization	Question 7 Comment
	required to implement a new maintenance frequency. The implementation plan should account for outage time, especially nuclear plants that have extended operating cycles. 5. Table 1b Protective Relays Level 2 Monitoring Attributes includes input voltage or current waveform sampling three or more times per power cycle. No further guidance is provided in the reference documents. If this sampling rate is not provided in the specification by the manufacturer, what can the entity use to demonstrate that the attribute is satisfied? Please provide additional guidance. 6. Consider numbering the tables to improve cross-referencing the entries in program documentation. This will allow entities to reference in program documents exactly which activities are being implemented in accordance with the standard. 7. Requirement 1.1 states, “Identify all Protection System components.” This is too broad and must be clarified.

Response: Thank you for your concern.

1. The Generator Owner, as defined within V5 of the NERC Functional Model, includes, “Design and authorize maintenance of generation plant protective relaying systems…” No maintenance activities are assigned to the Generation Operator within the Functional Model.
2. Requirement R3 and Attachment A provide the framework and requirements to develop and implement a performance-based maintenance program as you suggest.
3. “Grace periods” within the Standard are not measurable, and would probably lead to persistently increasing intervals. However, an entity may establish an internal program with grace-period allowance, as long as the entire program (including grace periods) does not exceed the intervals within the Standard.
4. The Implementation Plan has been revised in consideration of your comment.
5. This attribute is only relevant to microprocessor-based relays; no other technology possesses this attribute. The entity should contact the manufacturer to obtain this information.
6. The Tables have been completely revised in consideration of your comment.
7. Requirement 1, part 1.1 has been modified to state, “Address all Protection System component types.”

Organization	Question 7 Comment
Consumers Energy Company	In the Standard, Footnote 2 and Footnote 3 are identical. We presume that some information has been omitted. We do not agree that Footnotes are an appropriate method of providing information that is important to the application of the Standard. Important information should be provided within the standard text.
Response: Thank you for your comments. The footnotes have been removed.	
Nebraska Public Power District	1. 4.2.5.1 (And elsewhere in the standard) Please define auxiliary tripping relays. 2. 4.2.5.5 Do station "system connected" service transformers that do not supply house load for the generating unit, other than during start up or emergency conditions, fall under this clause? If so, can these transformers be eliminated if the house load can be back-fed from "generator connected" service transformer switchgear? What if there are redundant "system connected" feeds? 3. R1 1.4 Clarification requested. This wording would suggest all battery activities fall under Table 1.a. exclusively. 4. R4 4.3 Does initiation of activities require documentation, or is inclusion of "initiation" in the testing procedure sufficient evidence? 5. Tables 1b &1c: Suggestion: If at all possible, combine and simplify. The number of sub clauses and nuances that are being described in these sections (with little change to interval or procedures for that matter) is overwhelming. These two tables are setting RE's and System Owners up for making errors. Implementation and auditability should be the focus of this standard, SIMPLIFY. 6. SPS - Does the output signal need to be verified, or does the actual expected action need to be verified. Actual expected action would affect electrical generation production for NPPD's SPS.
Response: Thank you for your comments. 1. Please see FAQ II.4.C, II.4.D, II.4.E, II.4.F, II.4.G, and Sections 2.4 and 15.3 of the Supplementary Reference document for discussion regarding auxiliary relays. 2. The "load" being served by the station service transformer may be essential to operation of the generating plant, and therefore is not	

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the same as general distribution system load. Therefore, the SDT believes that these system components must remain within the Applicability section of the Standard. This is not affected by redundancy. 3. The Tables have been completely revised in consideration of your comment. Please see the new Table 1-4 for these activities. 4. As indicated in Measure M4, the SDT believes that documentation such as work orders, etc., is necessary. 5. The Tables have been completely revised. **6.** The draft Standard requires that the expected action is verified. This may be conducted in overlapping segments, and a simulation may be sufficient to verify in some cases.	
CenterPoint Energy	CenterPoint Energy believes the proposed Standard is overly prescriptive and too complex to be practically implemented. An entity making a good faith effort to comply will have to navigate through the complexities and nuances, as illustrated by the extensive set of documents the SDT has provided in an attempt to explain all the requirements and nuances. The need for an extensive “Supplementary Reference Document” and an extensive “Frequently Asked Questions Document”, in addition to 13 pages of tables and an attachment in the standard itself, illustrate that the proposal is too prescriptive and complex for most entities to practically implement. CenterPoint Energy is opposed to approving a standard that imposes unnecessary burden and reliability risk by imposing an overly prescriptive approach that in many cases would “fix” non-existent problems. To clarify this point, CenterPoint Energy is not asserting that maintenance problems do not exist. However, requiring all entities to modify their practices to conform to the inflexible approach embodied in this proposal, regardless of how existing practices are working, is not an appropriate solution. Among other things, requiring entities to modify practices that are working well to conform to the rigid requirements proposed herein carries the downside risk that the revised practices, made solely to comply with the rigid requirements, degrade reliability.
Response: Thank you for your comments. The SDT has extensively revised the Tables and the Standard in efforts to simplify and remove complexity. FERC Order 693 and the approved SAR for this project directed the SDT to establish both maximum maintenance intervals and minimum maintenance activities within the revised Standard.	
BGE	1. Comment 7.1. The standard, FAQs, and supplementary reference all make references to upkeep

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	and include in "upkeep" changes associated with manufacturer's service advisories. The FAQs include statements that the entity should assure the relay continues to function after implementation of firmware changes. This statement is uncontestable as general principle but is problematic in its inclusion in an enforceable standard because there is no elaboration on what the standard expects, if anything, as demonstration of an entity's execution of this responsibility. PRC-005-2 appropriately focuses on implementation of time-based, condition based, or performance based PSMPs; but addressing service advisories does not fit well with any of these ongoing preventive maintenance activities. It is instead episodic, more like commissioning after upgrades, or corrective maintenance work generated by condition-based alarms or anomalies discovered by analyzing operations. The standard appropriately steers clear of imposing requirements for these latter responsibilities as long as execution of an ongoing maintenance program is being demonstrated. BGE recommends that implied inclusion of service advisories should be removed from the standard and supporting documents. 2. Comment 7.2 R1.1 Requires the identification of all protection systems components. But it provides no elaboration on the level of granularity expected or acceptable means of identification. It is unlikely that the SDT expected the unique identification of every discrete component down to individual test switches or dc fuses. In the case of current transformers, several of which, or even dozens of which may be connected to a single relay there is no apparent reliability benefit that comes from indentifying them uniquely so long as it is proven that a protection system is receiving accurate current signals from the aggregate connection. (It may be argued that the revised definition of "protection systems" eliminates the need to include CT's under R1.1 but that's just one interpretation.) Some discrete components of communication systems may exist in an environment that is not owned by or known to the protection system owner. Additionally all protection system components may be indentified in documents that are current and maintained but not in the form of a specific searchable list that is limited to components that are within the scope of PRC-005. Examples may be indexed engineering drawings that indentify relays and other components for each protection systems or scanned relay setting and calibration documents that are current but not attached to searchable metadata. It is unclear whether or not these would be considered acceptable identification meeting R1.1. If they are not then the implementation plan for R1 is in all probability unachievable. BGE requests that the SDT provide more elaboration on R1.1 in the standard and in

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	the supporting documents. 3. Comment 7.3 For clarity footnote 1 to R1 which excludes devices that sense non-electrical signals should explicitly say that the auxiliary relays, lockout relays and other control circuitry components associated with such devices are included. The matter is well-addressed in the FAQ's but could easily be misunderstood if not included here.
Response: Thank you for your comments. 1. "Upkeep" has been removed from the definition of Protection System Maintenance Program, and from the Supplementary Reference and FAQ documents. 2. Requirement R1, part 1.1, has been revised to state, "Address all Protection System component types." 3. The SDT believes that these components are clearly included within the scope of dc control circuits.	
WECC	1. Compliance believes it will be difficult to demonstrate compliance when an entity chooses Condition Based Level 2 or Level 3 maintenance as the details of the requirements are still open to interpretation. The FAQ has answers to specific questions that are multiple choices. 2. Breaking down this standard into this level of granularity requires supplementary documents to understand it and for auditors to understand how to determine compliance. Industry standards are specific to equipment types and should be allowed to set intervals and maintenance tasks rather than a one-size fitting all approach.
Response: Thank you for your comments. 1. The Tables have been completely revised to clarify the monitoring attributes and related intervals and activities. 2. FERC Order 693 and the approved SAR for this project directed the SDT to establish both maximum maintenance intervals and minimum maintenance activities within the revised Standard.	
Constellation Power Generation	1. Constellation Power Generation does not agree with the changes to Voltage and Current Sensing inputs to protective relays in Table 1a. It is inferring that the only way to complete testing on these components to satisfy NERC is to complete online testing, which is dangerous and does not improve

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	the reliability of the BES. In fact, it can be argued that it decreases the reliability of the BES. The verbiage should be changed back to what was originally proposed to allow for offline testing. 2. Furthermore, Constellation Power Generation does not agree with several of the inclusions of generator Facilities in this standard. For example, in 4.2.5.1, the proposed standard looks to include any components that can trip the generator. At a nuclear facility, this could include protection of motors at the 4 kV level that may trip the generator due to NRC regulated safety issues. This should not fall under NERC jurisdiction. 3. The inclusion of station service transformers is another inclusion that should not be in this standard. There is no difference between a station service transformer and a transformer serving load on the distribution system. This has no impact on the BES, which is defined as the system greater than 100 kV. 4. Additionally, CPG has concerns regarding the vague language of R1.1, which requires the identification of all protection systems components. It provides no elaboration on the level of granularity expected or acceptable means of identification. It is unlikely that the SDT expected the unique identification of every discrete component down to individual test switches or dc fuses. In the case of current transformers, several of which, or even dozens of which may be connected to a single relay there is no apparent reliability benefit that comes from identifying them uniquely so long as it is proven that a protection system is receiving accurate current signals from the aggregate connection. (It may be argued that the revised definition of “protection stems” eliminates the need to include CT’s under R1.1 but that’s just one interpretation.) Some discrete components of communication systems may exist in an environment that is not owned by or known to the protection system owner. Additionally all protection system components may be identified in documents that are current and maintained but not in the form of a specific search-able list that is limited to components that are within the scope of PRC-005. Examples may be indexed engineering drawings that identify relays and other components for each protection systems or scanned relay setting and calibration documents that are current but not attached to search-able meta data. It is unclear whether or not these would be considered acceptable identification meeting R1.1. If they are not then the implementation plan for R1 is in all probability unachievable. 5. CPG requests that the SDT provide more elaboration on R1.1 in the standard and in the supporting

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	documents. In that vein, to clarify footnote 1 to R1 which excludes devices that sense non-electrical signals, it should explicitly say that the auxiliary relays, lockout relays and other control circuitry components associated with such devices are included. The matter is well-addressed in the FAQ's but could easily be misunderstood if not included here. 6. Lastly, Constellation Power Generation would like to voice concern over the expedited process in which this standard is being developed. Voting within a week of submitting comments does not leave enough time for the drafting team to thoroughly vet through the issues and identify much needed changes, let alone implement them.
Response: Thank you for your comments. 1. The intent of the cited section is to provide examples of how an entity <u>might</u> perform the testing. Any examples listed in either of the supporting documents should be looked upon as suggestions; these suggestions are not considered to be a complete list of the methods available. To the contrary, the Standard and the supporting documents were written considering that there are many ways to achieve a good test. Leeway is certainly available in how an entity complies with the Standard as the maintenance activities generally specify "what" must be achieved but not "how" an entity achieves it. Please see FAQ II.3.D. 2. FAQ III.2.A specifies that relays that trip breakers serving station auxiliary loads such as fans, pumps, and fuel handling equipment need not be included in the program even if loss of those loads could result in the tripping of the generator. 3. The "load" being served by the station service transformer may be essential to operation of the generating plant, and therefore is not the same as general distribution system load. Therefore, the SDT believes that these system components must remain within the Applicability section of the Standard. 4. Requirement R1, part 1.1, has been revised to state, "Address all Protection System component types." 5. Requirement R1, part 1.1, has been revised to state, "Address all Protection System component types." The SDT believes that the components associated with devices that sense non-electrical signals are clearly included within the scope of dc control circuits. 6. This Standard has been designated for an expedited process in order to achieve approval in the minimum time possible.	
Pepco Holdings, Inc. - Affiliates	Dates of the Supplemental Reference Documents in Section F of the standard need to be updated. 1. The word "calendar" is used widely to define month and year intervals. Sometimes causes

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	confusion, need definition/examples. 2. The level 2 table regarding Protection Station dc supply states that level 1 maintenance activities are to be used, but then goes on to give a list of Maintenance Activities that don't match those in level 1. Which activities shall we use? Same situation for Station DC Supply (battery is not used) where the 18 month interval is missing. 3. Req 1.1: "All Components" wording should say something like all components covered in our plan
Response: Thank you for your comments. 1. Section 8.4 of the Supplementary Reference document provides an example to assist in this determination. A "calendar year" is a single number year on the Gregorian calendar; a calendar month is any one of the twelve months within a single calendar year. 2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. 3. Requirement R1, Part 1.1, has been revised to state, "Address all Protection System component types."	
SERC Protection and Control Sub-committee (PCS)	1. Descriptors in the "type of the protection system component" column need to be consistent between 1A, 1B and 1C. 2. Also, in the tables, please clarify "complete functional trip test" for UVLS and UVLS trip tests since the breaker is not being tripped. Facilities Section 4.2.1 "or designed to provide protection for the BES" needs to be clarified so that it incorporates the latest Project 2009-17 interpretation. The industry has deliberated and reached a conclusion that provides a meaningful and appropriate border for the transmission Protection System; this needs to be acknowledged in PRC-005-2 and carried forward. 3. We commend the SDT for developing such a clear and well documented second draft. The SDT considered and adopted many industry comments on the first draft. It generally provides a well reasoned and balanced view of Protection System Maintenance, and good justification for its maximum intervals. The SERC Protection & Control Subcommittee generally agrees that this second draft will be beneficial to BES reliability.

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Response: Thank you for your comments. 1. The Tables have been rearranged and considerably revised to improve clarity. 2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 3. Thank you for your comment.	
Dynegy Inc.	For protection system component verification, flexibility is needed subsequent to a system event to allow the analysis of a protection system operation to be utilized as a protection system component verification. We believe this flexibility is needed and should be incorporated in Requirement R4.
Response: Thank you for your comments. Operational results, if desired by an entity, MAY be used to meet maintenance requirements to the degree that they verify, etc., the relevant performance. The entity must determine if their use is effective.	
MidAmerican Energy Company	1. From the compliance registry criteria for generator owner/operator and the language in 4.2.5.3 it is implied that the intent is that protection systems for individual generators less than 20 MVA would not be covered by PRC-005. To make this clear in the PRC-005-2 standard, the following footnote to section 4.2.5.3 is recommended: Protection systems for individual generating units rated at less than 20 MVA in aggregated generation facilities are not included within the scope of this standard. The Request for Interpretation of a Reliability Standard submitted March 25, 2009 indicates that a protection system is only subject to the NERC standards if the protection system interrupts the BES and is in place to protect the BES. The following changes are recommended to clarify this in the standard: A.3. Purpose: To ensure all transmission and generation Protection Systems protecting and affecting the reliability of the Bulk Electric System (BES) are maintained. A.4.2.1. Protection Systems applied on, or and designed to provide protection for the BES.B.R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a PSMP for its Protection Systems that use measurements of voltage, current, frequency and/or phase angle to determine anomalies and to trip a portion of the BES and that are applied on, or and are designed to

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	provide........ 2. FERC Order 693 includes the directive that “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”. If unanticipated conditions (e.g. force majeure) of the bulk-power system do not allow outages to complete protection system maintenance as required by the standard without compromising the reliability of the system delay of the particular maintenance activity should be allowed. This provision should be included in the standard in R4.
Response: Thank you for your comments. 1. This is an issue for your regional BES definition. The SDT has drafted the Standard to apply to all NERC entities with due regard for the applicable BES definition. 2. “Grace periods” within the Standard are not measurable, and would probably lead to persistently increasing intervals. However, an entity may establish an internal program with grace-period allowance, as long as the entire program (including grace periods) does not exceed the intervals within the Standard.	
Southern Company Transmission	1. General FAQ1) Attached is an elementary drawing showing a typical transmission line relay protection scheme utilizing SEL-351S and SEL-321 microprocessor relays. Does this qualify as partially monitored control circuitry? See pdf file Control Elementary_1-07-13 & Control Elementary_2-07-13in email documentation sent to Al McMeekin. If not, and this is an unmonitored circuit, what would be the appropriate maintenance interval (6 years or 12 years) for the Control and Trip Circuits from page 9 of PRC-005-2? The description of the two choices is ambiguous See pdf file PRC-005-2_clean_2 010June8.pdf in email documentation sent to Al McMeekin. If not, what would it take to make this circuit partially monitored (including inputs)? 2) Table 1a, page 9, row 2 (Voltage and Current Sensing Inputs) Question - Does this mean secondary quantities from CT’s and VT’s only? If so, please consider changing the wording from “Voltage and Current Sensing Inputs” to “CT and VT secondary quantities”. 3) Table 1a, page 9, row 3 (Control and trip circuits with EM contacts)Question - Does "electromechanical trip or auxiliary contacts" mean EM protective relay outputs and EM tripping/lockout tripping contacts only? Or does it also include any part of the trip circuitry such as

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	cutout switch contacts and breaker trip coils plus associated aux. breaker contacts. For example, the schematic with a microprocessor relay described in the first bulleted item could be considered an unmonitored EM control circuitry (6 year interval). Is this because of the mechanical breaker aux contacts, breaker maintenance switch, and FT-1 test switch? If so, how could any control circuitry fall in the solid state trip contacts category (12 year interval)? 4) Table 1a, page 9, rows 3, 4, 5, 6 - Please consider rewording these to make it clear where control schemes with MP relays that do have trip coil / circuit monitors but don't meet the Partially Monitored requirements fit. (Does this type scheme fit in the 6 year trip test category or the 12 year category?) 5) Table 1a, page 12, row 1 - The maintenance requirements are not the latest wording used for all other Protective Relays. Please consider changing for consistency. 6) Table 1b, page 13, row 1 (Protective Relays) - Line three of the maintenance activities requires us to check inputs and outputs. The last maintenance item is to verify correct operation of output actions that are used for tripping. Question - How is this different than the line three maintenance requirements to check inputs and "outputs"? 7) Table 1b, page 14, rows 1 and 2 - Consider combining these into one row. The maintenance intervals and maintenance activities are these same. Please specify what is required for UFLS and UVLS control schemes). 8) Table 1b, page 14, rows 1 - The first sentence is very general for a monitoring attribute. ("Monitoring of Protection System component inputs, outputs, and connections with reporting of monitoring alarms to a location where action can be taken.") Consider deleting this row or make it more specific. 9) Table 1b, page 14, row 2 [Control Circuitry (Trip Circuits) (except for UFLS/UVLS)]Question: Should there be a 12 year functional trip test requirement for this partially monitored control circuitry? Should this be added to Table 1b? 10) Table 1b, page 14, row 1 [Control Circuitry (Trip Circuits) (except for UFLS/UVLS)] - It states Monitoring of Protection System component inputs, outputs, and connections ... Question - what does "inputs" mean? There are Protection System components such as protective relays, control circuitry, station dc supply, associated communications systems, etc. Does this mean we must monitor inputs to any or all of these Protection System components? How would this be

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	accomplished? 11) Table 1c, page 18, row 4 - Should there still be a requirement to trip breakers by all trip coils every 6 years? Supplementary Reference Document 12) Question on Figure 1, page 27 - Box 1 denoting Protection Relays includes Aux devices, Test or Blocking Switches. The Aux devices Test or Blocking Switches should be part of Box 3 (Control Circuitry). Please correct or note accordingly. FAQ Document 13) On Page 30, please add an Example with Partially Monitored (Level 2) Control Circuit. 14) On the Control Circuit Decision Tree on page 36, the flow chart does not match the current Table 1 requirements. They match the previous version which is described in the first question of this document. We still propose leaving the flow chart on page 36 as is and change Table 1 to match the original requirements. 15) Please consider adding a diagram /elementary drawing of a Partially Monitored Control Circuit showing the trip output contacts, inputs, etc that must be monitored to meet the Monitoring Attributes / Requirements. A diagram showing an Unmonitored control scheme and what it would take to make it Partially Monitored would be helpful too. Additional General FAQ 16) PRC-005-2, R1 requires the Functional Entity to establish a Protection System Maintenance Program (PSMP). It is not clear if this standard establishes a specified frequency for reviewing and updating the PSMP itself or the PSMP criteria outlined in subparts 1.1 through 1.4. By comparison, EOP-005-1 System Restoration Plans, requires the Functional Entity to (a) have a restoration plan and (b) to review and update the restoration plan annually (see EOP-005-1, R1 and R2). This approach to a comprehensive and periodic review considers the PSMP as a whole and is independent of the specific maintenance methods (time-based, condition-based, or performance-based) and maintenance intervals for those respective methods. It is noted however that PRC-005 Attachment A mentions annual updates to the list of Protection System component. According to the

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	Attachment's subtitle, Criteria for a Performance-Based Protection System Maintenance Program, this annual update seems limited to performance-based maintenance and not inclusive of other maintenance methods. The recommendation is to evaluate the need for a periodic review of the PSMP as a whole. 17) R1, Criteria 1.1, and companion VSL. This Criterion requires the identification of all Protection System components. The VSL for R1 uses a percent-based approach to parse out different quantities of components across the four VSL categories. This implies that a Functional Entity must have the ability to put a numerical quantity on its various components and should be able to demonstrate within certain tolerances that its components are included (or counted). If the number of components within scope amount to hundreds or thousands of individual items, the PSMT SDT should consider the Functional Entities' ability to track and quantify the items for a compliance demonstration. If an entity is not able to reasonably quantify which components are in scope, demonstrating compliance on a percent-basis may prove difficult or impossible. Further review may indicate the need to reformat the VSL. Similar concerns are noted in other VSLs (R2, R3, and R4) and in Attachment A where percentage-of-components are mentioned. 18) R4 essentially requires the Functional Entity to implement its PSMP. R4 takes care to highlight the specific task of "identification of the resolution of all maintenance correctable issues." It is noted that other "identification tasks" are included as criterion for the PSMP in R1. If these tasks are all appropriately categorized as identification-type tasks, it may be more efficient to restructure the standard by incorporating this task into R1 with the other criteria. R4 could remain as a basic implementation requirement with more detail provided in subparts 4.1, 4.2, and 4.3. 19) Footnote No. 2 describes maintenance correctable issues and could be interpreted as a potential new term for inclusion in NERC's Glossary of Terms. The PSMT SDT should conduct further review of this terminology as a potential new Glossary term. 20) At R4, subpart 4.3, insert "design" such that it reads as follows: "Ensure that the components are within acceptable design parameters at the..." Also, this subpart duplicates Footnote No. 3 which describes "maintenance correctable issues" and was established in the main requirement R4 at Footnote No. 2.

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Response: Thank you for your comments. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 2. This portion of the definition of Protection System has been revised. Also, the Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-3. 3. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 4. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 5. The Tables have been rearranged and considerably revised to improve clarity. 6. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 7. The Tables have been rearranged and considerably revised to improve clarity. 8. The Tables have been rearranged and considerably revised to improve clarity. 9. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 10. Some examples of input may include, but are not limited to: breaker fail initiate, start timer. This cannot be an all-inclusive list as any given scheme could have many variations. In short, if your scheme requires a specific input to function properly then you must have that input maintained; if your scheme has a specific output that must function then it must be maintained. If the input or output is used for a non-protective function (such as, but not limited to, Sequence-of-Events Recorder, alarm or indication) then it does not have to be maintained under this Standard. See Section 15.3 of the Supplementary Reference and FAQ II.2.L. 11. Yes. 12. The diagram is for illustrative purposes only, and is intended to demonstrate all devices which need to be included within a PSMP. Box 1 shows the cited devices as being within the relay panel, and makes no distinction regarding what specific type of Protection System component is being addressed. The preceding Table has been revised to avoid this conclusion. 13. The Tables have been revised to remove descriptions of various levels of monitoring. 14. The decision trees have been removed. 15. The Tables have been revised to remove descriptions of various levels of monitoring.	

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16. The expectation is that an entity's PSMP will be current. No periodicity is provided. However, in Attachment A, the performance-based program necessarily requires an ongoing review of the program to assure that it is still relevant. 17. Requirement R1, part 1.1, has been revised to state, "Address all Protection System component types." 18. The SDT believes that the identification of maintenance-correctable issues is properly an issue for implementation of the PSMP, not establishment of the PSMP. 19. The referenced footnote has been removed and a new definition established for this Standard only. 20. The SDT disagrees. The acceptable parameters for a specific application may not be identical to the design parameters for the component.	
FirstEnergy	Implementation Plan a. We do not support the 3 month implementation timeframe for Requirement 1. For many entities, it will take some time to develop a sound PSMP that meets the new PRC-005-2 standard. We suggest a 12 month implementation which we believe is more logical and in alignment with the implementation timeframe for Protection System Components with maximum allowable intervals of less than 1 year, as established in Table 1a. b. Although we support the implementation timeframes for Requirements R2, R3, and R4, we do not support the required periodic percentages of protections systems to be completed. There could be numerous reasons where an entity has to adjust its program schedule which could lead to noncompliance with these percentage milestones. We suggest simply requiring 100% completion of the maintenance per the maximum maintenance intervals. Alternatively an entity should have the flexibility to indicate they have fully transitioned to the new standard during the early stages of the implementation plan if their existing maintenance practices meet or exceed the standards minimum expectations. Doing so should negate the need to produce the "% complete" implementation status.
Response: Thank you for your comments. a. The Implementation Plan has been modified in consideration of your comment. b. The SDT disagrees and feels that a "phased" Implementation Plan is appropriate. The Implementation Plan has been revised to	

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	clarify that the percentages are minimums, not absolute.
American Transmission Company	1. It is appreciated that the SDT is attempting to provide options for maintenance and testing programs. Practically speaking, it will be difficult to perform any type of program outside of Time-Based Maintenance (TBM). Too many circuits are a mix of technology. For example, a line may have microprocessor relays for detecting and tripping line faults, but the bus differential lockout could also trip the line breaker. One may be partially monitored and the other unmonitored. It will force the utility to perform maintenance at the shorter of the maintenance cycles. Additional time and cost will be required to organize and switch out the applicable equipment for the outage, approximately doubling the cost associated with performing these trip tests. When entities are required to maintain tens of thousands of these devices, the simplest approach will be to revert to TBM. ATC does not support the existing 2nd Draft of PRC-005-2 Standard because it is our opinion that: o There is a high probability that system reliability will be reduced with this revised standard. o The number of unplanned outages due to human error will increase considerably. o Availability of the BES will be reduced due to an increased need to schedule planned outages for test purposes (to avoid unplanned outages due to human error). o To implement this standard, an entity will need to hire additional skilled resources that are not readily available. (May require adjustments to the implementation timeline.) o The cost of implementing the revised standard will approximately double our existing cost to perform this work. 2. ATC requests that relevant reliability performance data (based on actual data and/or lessons learned from past operating incidents, Criteria for Approving Reliability Standards per FERC Order 672) be provided to justify the additional cost and reliability risks associated with functional testing. 3. Under a Performance-Based Program, what happens if the population of components drops below 60 (as all will eventually)? Is there an implementation period to default to TBM? 4. Are the internal relays and timers associated with a circuit breaker included as part of the protection scheme? In the Independent Pole Operation breakers (IPO), there are various internal schemes built to protect for pole discordance (one pole open, two closed, event measured over time frame

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	(milliseconds)), these schemes may re-trip the breaker, initiate breaker failure protection or trip a bus lock out relay. In DC control schemes fuses and panel circuit breakers protect for wiring faults. Do these devices need to be tested? Is there an obligation to test the distribution circuit breakers for correct operation points? Is there an obligation to replace fuses after a defined time period?
Response: Thank you for your comments. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see the new Tables. 2. The Standard does not preclude an entity from largely utilizing other methods of verification, although functional testing may be the easiest to achieve. 3. The entity must revert to TBM if the population falls below 60. There is no implementation period; the SDT believes that the annual PBM review will alert the entity that the population is nearing 60, and allow the entity to react to the diminishing component population accordingly. 4. Only those control circuit components necessary for proper Protection System operation are included. As noted, many breakers have numerous other internal auxiliary functions (gas pressure, etc.) that are not relevant. A purely-functional test may address many of the issues cited. There is no obligation to test either distribution circuit breakers or dc panel fuses.	
NERC Staff	NERC staff is pleased with the current iteration of this standard. The staff understands that while PRC-005-2 has historically been the most frequently violated standard, it has mostly been due to documentation issues. The standard has not been much of a heavy hitter in causal or contributive aspects, and with respect to relay operations, there have been very few times that lack of maintenance has been the problem. 1. NERC staff does propose a slight change to 4.2.5.1. The concern is that 4.2.5.1 could be interpreted to apply to devices that protect the generator as opposed to those that protect the Bulk Electric System. The suggested language is as follows: “Protection System components that act to trip generators that are part of the BES, either directly or via generator lockout or auxiliary tripping relays.” 2. Additionally, staff suggests some changes to R1. In that requirement, the PSMP covers “Protection Systems that use measurements of voltage, current, frequency and/or phase angle to determine

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	anomalies and to trip a portion of the BES...” It probably would be better if the list was limited to voltage and current or if the list was replaced with electrical quantities. The former would be okay since voltage and current are the only two electrical quantities that relays measure directly. To remove ambiguity, the most inclusive way to rephrase this is probably the latter alternative, to change the requirement to, “...that use measurements of electrical quantities to determine anomalies...” 3. Finally, Footnotes 2 and 3 (in Requirement 4) are identical. Unless that’s intentional, one should be removed. (And note that Footnote 2 is missing a period.)
Response: Thank you for your comments. 1. The essence of your suggestion is already addressed within 4.2.5 itself. 2. The definition of Protection System has been revised to address your suggestion. 3. The footnotes have been removed.	
MEAG Power	No comment.
Exelon	1. Nuclear generators are licensed to operate and regulated by the Nuclear Regulatory Commission (NRC). Each licensee operates in accordance with plant specific Technical Specifications (TS) issued by the NRC which are part of the stations’ Operating License. TS allow for a 25% grace period that may be applied to TS Surveillance Requirements. Referencing NRC issued NUREGs for Standard Issued Technical Specifications (NUREG-143 through NUREG-1434) Section 3.0, "Surveillance Requirement (SR) Applicability," SR 3.02 states the following: "The specified Frequency for each SR is met if the Surveillance is performed within 1.25 times the interval specified in the Frequency, as measured from the previous performance or as measured from the time a specified condition of the Frequency is met." The NRC Maintenance Rule (10 CFR 50.65) requires monitoring the effectiveness of maintenance to ensure reliable operation of equipment within the scope of the Rule. Adjustments are made to the PM (preventative maintenance) program based on equipment performance. The Maintenance Rule

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	program should provide an acceptable level of reliability and availability for equipment within its scope. The NRC has provided grace periods for certain maintenance and surveillance activities. Exelon strongly believes that SDT should consider providing this grace period to be in agreement and be consistent with the NRC methodology. Not providing this grace period will directly affect the existing nuclear station practices (i.e., how stations schedule and perform the maintenance activities) and may lead to confusion as implementing dual requirements is not the normal station process. Nuclear generating stations have refueling outage schedule windows of approximately 18 months or 24 months (based on reactor type). If for some reason the schedule window shifts by even a few days, an issue of potential non-compliance could occur for scheduled outage-required tasks. The possibility exists that a nuclear generator may be faced with a potential forced maintenance outage in order to maintain compliance with the proposed standard. For the requirements with a maximum allowable interval that vary from months to years (including 18 Months surveillance activities), the SDT should consider an allowance for NRC-licensed generating units to default to existing Operating License Technical Specification Surveillance Requirements if there is a maintenance interval that would force shutting down a unit prematurely or face non-compliance with a PRC-005 required interval. Therefore, at a minimum, maintenance intervals should include an allowance for any equipment specifically controlled within each licensee's plant specific Technical Specifications to implement existing Operating License requirements if such a conflict were to occur. 2. PECO would like to have the implementation plan provide at least 1 year for full implementation of the new standard. This will provide adequate time for development of documentation, training for all personnel, and testing then implementation of the new process(es).

Response: Thank you for your comments.

1. The SDT understands that nuclear power plants are licensed and regulated by the NRC, has a general understanding of the role that plant Technical Specifications (TS) and associated Surveillance Requirements (SR) in the facilities' operating licenses, and has tried to be sensitive to potential conflicts between PRC-005-2 and NRC requirements.

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The SDT believes that the majority of components making up the protection systems for in-scope generating facilities as discussed in Section 4.2.5 of the Standard would be considered balance of plant equipment and, therefore, not subject to NRC-issued TS and associated SR requirements. While availability of plant auxiliary sources to the plant's safety related equipment is addressed by TS and associated SR requirements, these documents are focused on the effects that the availability of these transformers have on reactor safety rather than specifying maintenance and testing requirements for the Protection Systems for these transformers. The SDT recognizes that some battery systems may serve as a source of DC power to both reactor safety systems and to Protection Systems discussed in Section 4.2.5. The SDT acknowledges that there might be plant TS and SR applicable to these batteries. However, the SDT believes that the 3-month and 18-month inspection requirements called for in PRC-005-2 would be no more onerous than plant TS requirements for routine online safety system battery inspections and, furthermore, would not necessitate a plant outage. The SDT recognizes that the PRC-005-2 requirement for validating battery design capability via battery capacity testing would require a plant outage. However, it is the opinion of the SDT that the maximum allowed battery capacity testing intervals of not to exceed 6 calendar years for vented lead acid or NiCad batteries (not to exceed 3 calendar years for VRLA batteries) could easily be integrated within the plant's routine 18-month to 2-year interval refueling outage schedule. The SDT believes that PRC-005-2 is complementary to the NRC Maintenance Rule in that PRC-005-2 requirements allow for the leveraging of the entire electrical power industry experience in establishing minimum maintenance activities and maximum allowed maintenance intervals necessary to ensure reliable Protection System performance. Please see Supplemental Reference Section 8.4 for further discussion for the SDT's rationale for exclusion of grace periods. Please see FAQ IV.2.C for further discussion of impact of PRC-005-2 testing requirements on power plant outage schedules. The challenge of integrating PRC-005-2 testing requirements with a plant's outage schedule is not unique to nuclear plants. Finally, the SDT notes that an entity may build grace periods into its own PSMP as long as the maximum allowed time intervals of PRC-005-2 are not exceeded. If an entity wishes to build a 25% grace period into its program, it may do so by setting its program maintenance and testing intervals at <80% of the PRC-005-2 maximum allowable time interval. 2. The Implementation Plan has been modified in consideration of your comments.	
Hydro One Networks	1. Footnotes 2 and 3 on page 4 are identical. Delete footnote 3. 2. UFLS systems by design can suffer random failures to trip. It would make sense for a requirement to exist to perform maintenance on the UFLS relay as their failure to operate may affect numerous distribution level feeders. However maintenance on associated DC schemes connected to the

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	devices should only be done on the same frequency as maintenance on the relevant interrupting devices. Consideration should be given to exempting schemes that have a maintenance program in place on those distribution level devices from PRC-005 Standard-specified maintenance intervals. Such Standard-specified intervals could apply to interrupting devices that have no maintenance program in place.
Response: Thank you for your comments. 1. The footnotes have been removed. 2. The Tables have been rearranged and considerably revised to improve clarity, and many activities related to UFLS have been removed. Please see the new Tables.	
Progress Energy Carolinas	1. R1.1.1 states that "all" protection system components be identified. Does the term "all" refer to the major components identified in the Protection System definition (protective relays, communication systems, voltage and current sensing devices, station dc supply, and control circuitry) or does it include all sub-components (jumpers, fuses, and auxiliary relays used in dc control circuits and communication paths/wavetraps/tuners/filters)? We assume the former but request clarification. 2. Draft Implementation Plan for PRC-005-02: The phased implementation plan for R2, R3, and R4 seems reasonable. However, the three-month implementation plan for R1 seems extremely short. Utilities will have to change procedures, job plans, basis documents, provide training, and change intervals in their work tracking databases. In addition, if the utility wants to take advantage of the longer intervals allowed by partial monitoring, significant print work must be performed up front. 3. Descriptors in the type of the protection system column needs to be consistent between 1A, 1B and 1C. In the tables, please clarify "complete functional trip test" for UVLS and UVLS trip tests since the breaker is not being tripped.
Response: Thank you for your comments. 1. Requirement R1, Part 1.1, has been revised to state, "Address all Protection System component types." 2. This portion of the Implementation Plan has been revised to twelve months in consideration of your comment.	

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3. The Tables have been rearranged and considerably revised to improve clarity. Please see the new Tables.	
Manitoba Hydro	1. Once the new Standard is approved, NERC must allow for a greater implementation stage and no further changes proposed for the foreseeable future. It does take a lot of resources for a Utility to make the required changes in maintenance frequency templates or type of maintenance required as per the proposed "Standard". 2. Regarding the use of the term "Calendar" (i.e. end of calendar year) for maximum maintenance interval. Our utility uses end of fiscal year as our cutoff date for completing maintenance tasks for a given year. It would be considerable work for us to have to switch to end of calendar year with zero improvement in our overall reliability. We suggest it be left up to each utility to define their calendar yearly maintenance cycle when all tasks for that year must be completed.
Response: Thank you for your comments. 1. The implementation period for Requirement R1 has been extended from 3 months to 12 months in consideration of your comments. 2. With the vast array of entities subject to compliance monitoring, it would be very difficult for the ERO to assess compliance for varying "years." Additionally, the SDT understands that most compliance monitors currently request data on a calendar year basis when assessing compliance.	
Grant County PUD	PRC005-02 Comment We offer some comment for your consideration for incorporation into the Standard PRC-005-02 (draft) as presented in the May 27th 2010 PRC 005-02 "Standard Development Roadmap." RE: Comment on the 2nd Draft of the Standard for Protection System Maintenance and Testing" 1) The term "The Protection System Maintenance Program" (Page 2) appears to be centered on the concept of maintaining specific components as stand alone objects, and therefore infers that the resultant documentation be organized in a similar fashion. Neither is optimal from a practical or a functional perspective. Many rational work practices combine components (example, meggering from the relay input test switch through the cables and the CTs) in the interest of minimizing circuit intrusion and human error. For this reason, such maintenance practices are superior from a reliability standpoint. The emphasis on "components" in the current draft is, at best, tangential to NERC's

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	stated goal and purpose of PRC-005 to improve reliability. How would we fix this? We would insert the phrase “or Element”-as defined in NERC’s Glossary of Terms to include “one or more components / devices with terminals that measures voltage, current, frequency and/or phase angle” to determine anomalies and to trip a portion of the BES” immediately after any occurrence of the word “component” in each of the Requirements or in a Definition paragraph, intending it to be applied globally to R-1 through R4. This would foster the validity of maintenance activities being applied to aggregations of components - “Elements”-such as would occur during Verification of DC control circuitry or through the employment of fault data analysis. 2) Protection System Maintenance Program. The categorization of maintenance into 7 maintenance activities is welcomed as advancing practices which foster BES reliability. Likewise we find the clarifications denoted by superscripts 1 and 2 helpful. However....under C: MEASURES: M1, the last sentence of the paragraph provides: “For each protection system component, the documentation shall include the type of maintenance program applied (time based, etc), maintenance activities (1 or more of the 7 identified) and maintenance intervals.....” This measure goes beyond the requirements of the standard and should be revised consistent with the deletion of the previous R.1.1 as shown in track changes under the version 2 draft which had included the identification of the maintenance activity associated with each component. COMMENT: It should be apparent in reviewing the evidence that one or more of the 7 listed activity categories are represented. The proscription to explicitly call out these categories is thus redundant---the requirement being that at least one has to be identifiable in the program-and will cause unnecessary complications to the Entity and interpretation issues in the Compliance monitoring effort. We recommend that the words “maintenance activities” be removed from the last sentence in the paragraph pertaining to C: MEASURES: M1.We also believe it is unnecessary to restate the definition of “Protection System” in the Measure. 3) A fundamental incompatibility exists between NERC’s proposition of “maximum maintenance (time based) interval” and the typical CMMS PM generation algorithm. SPCTF members and regional compliance engineers have verbally represented that the “maximum maintenance interval” is a precise term “not to exceed-even by one day---” maximum, otherwise generating a fine-able Violation and that fixed intervals plus or minus a certain additional period of time to account for other operational exigencies are no longer going to be permitted. There is always an interval between the

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	time a CMMS PM is issued and its completion. The time interval between the issue date and the completion date is normally a period of time to allow maintenance staff to schedule their work in an orderly fashion. The maximum time based interval is fixed by the time period specified for issuance of the planned maintenance (PM) work order (e.g. every 3 years) and the defined period of time to complete the work (usually described as a percentage of the PM interval e.g. 25%). So predicating a PM issue date based on the last issue date plus a percentage of the interval time to complete the work is not inconsistent with a fixed time interval. Under the proposed tables, however, there is no accommodation for this predominate maintenance practice. Even if maintenance intervals were shortened to ensure that the required completion date as defined by program intervals does not exceed the NERC maximum interval as described in the tables, this will not be sufficient because auditors may conclude that the tables permit the use of only a single defined interval and not permit an additional defined period of time to schedule and complete the work. Remember, it is immaterial whether the Entity's interval is more stringent than the NERC maximum, a violation may occur if the maintenance is not performed within the Entity's maintenance interval, even if it is shorter than the NERC maximum. A precise maximum interval requires constant managerial intervention on the part of the Entity to ensure that operational exigencies do not cause violations on a component-by component (or element) basis. The shortened interval would tend to destroy the sense of rhythm and pattern which should be manifest in a time based program. Further, after one or more iterations, seasonal restrictions on outages begin to impinge requiring adjustments to be made to the Maintenance Program document to adjust the interval or maintenance activity. At best, it results in a clumsy way of doing business and requiring significantly more oversight into keeping the maintenance program document updated for presentation to auditors rather than focusing on prudent maintenance activities as desired by FERC Order 693. Auditing is not any more difficult if the Maintenance Program also specifies that a percentage of a fixed target / time interval is allowed to schedule and complete the work-as meeting the interval requirements of a time based maintenance program. This method allows for a fixed time for issuance of the work order and maintenance personnel some flexibility to schedule and complete their work within a defined period of time. We recommend to vote against adoption until some more workable solution is identified and disseminated, satisfying both the Compliance Authority and the affected Entities. Specifically, we recommend that the drafting team adopt "target" intervals with a +/- range of

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	acceptability, based on percentage or a fixed time per interval, which can be global for the Program or specific to the elements or components in question. The target intervals must be stated in the PSMP, the range of acceptability easily calculable and enforceable, and within the maximum intervals to be identified in the tables 1a, b, and c, satisfying compliance issues. This also allows the Entities to rationally plan their maintenance using existing CMMS technologies. 4) Within the Violation Security levels, we are aware of no activity by NERC to differentiate the relative criticality of components or Elements of the BES system. For example, protection system components or Elements in a regional switchyard may present a larger potential for disruption of the BES in the event of a mis-operation than does one associated with one generator among fifteen others and which is more electrically remote from and of less consequence to the BES. Unless and until this issue is addressed, both the PRC-005 maintenance and documentation will be less effective and more expensive than it could be. 5) PRC-005-02's proposed effective date is "See Implementation Plan." This is not adequate to provide regulated entities with appropriate notice of the Effective Date of PRC-005-2 standard. " 6) Additionally, NERC has not posted the "Implementation Plan" for comment in the same manner as the proposed standard and thus we are not able to comment on the schedule provided in the Plan. We understand that the retention and documentation cycles go back three years and that a regulated entity, depending on the effective date of this standard and the entity's audit cycle, will be audited to both PRC-005-1 and PRC-005-2 during the same audit period. Some further discussion should be given to allowing comment on the Implementation Plan because of the potential overlapping requirements during a single audit cycle.

Response: Thank you for your comments.

1. The draft Standard supports a variety of methods of designing the PSMP.
2. A definition of "Component" and "Component Type" has been added to the draft Standard. The SDT's intent is that this definition will be used only in PRC-005-2, and thus will remain with the Standard when approved, rather than being relocated to the Glossary of Terms. The Requirements and Measures have been modified to use these terms in a consistent manner. These defintions will assist in addressing your concern.

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3. This comment seems to suggest that a “grace period” should be permitted. “Grace periods” within the Standard are not measurable, and would probably lead to persistently increasing intervals. However, an entity may establish an internal program with grace-period allowance, as long as the entire program (including grace periods) does not exceed the intervals within the Standard. 4. Thank you for your comment. The VRFs address the reliability impact of the Requirements, while the VSLs simply address “how bad did you miss it?” 5. The Implementation Plan for Requirement R1 has been revised from 3 months to 12 months to address this comment. 6. The Implementation Plan was posted for comment, with a question on the comment form during the first posting. The Implementation Plan was not substantially revised for the second posting. During the implementation period, there will be some overlap between PRC-005-1 and PRC-005-2. An unattractive alternative would be to minimize the implementation period for PRC-005-2.	
Xcel Energy	1. R1.1 “Identify all Protection System Components” - does this mean that the PSMP must contain a “list”? Please explain what this means. If it is a list, then essentially it will be a dynamic database, not necessarily a “program” as defined in the PSMP 2. R1.3 “include all maintenance activities...” seems to be an indirect way of indicating that the entities PSMP must comply with the tables. Tables - the components related to DC Supply and battery are confusing. It the battery is the specific component then state “battery". If the charger is the specific component, then state “charger”. As currently written, one must sort through all of the different “Station DC Supply” line items to figure out what is required.- 3. In tables 1b and above, it is written “no level 2 monitoring attributes are defined - use level 1 maintenance activities” but then maintenance activities are listed that don’t match with Level 1 maintenance activities. Please clarify what exactly needs to be done if using Table 1 b and above.
Response: Thank you for your comments. 1. Requirement R1, Part 1.1, has been revised to state, “Address all Protection System component types.” 2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4.	

<table>
<tr><th>Organization</th><th>Question 7 Comment</th></tr>
<tr><td colspan="2">3. The Tables have been rearranged and considerably revised to improve clarity.</td></tr>
<tr><td>Northeast Utilities</td><td>1. R1.1 It is not clear what would constitute “all Protection System components”. Suggest the addition of a definition for “Protection System components”.R1.4 Suggest revise to read: “all batteries or dc sources”
2. Table 1a vented lead acid -- “Verify that the station battery can perform as designed by evaluating ...” -- Please define evaluating, including:
a. What is the basis for the evaluation?
b. Is 5% 10% 20% etc acceptable?
c. Where does baseline come from for older batteries?
3. Request clarification of 2.3 Applicability of New Protection System Maintenance Standards from Supplementary Reference. Specifically, please clarify if a functional trip test is needed to be performed on the distribution circuit breakers to protect the Bulk Electric System (BES) if these low side breakers are not part of the transmission path. (A diagram identifying the applicable breakers would be helpful in the Supplementary Reference)</td></tr>
<tr><td colspan="2">Response: Thank you for your comments.
1. Requirement R1, Part 1.1, has been revised to state, “Address all Protection System component types”..(a) The basis is related to the variation from the baseline. Please see FAQ II.5.G and II.5.F. (b) This is determined by the entity based on the application. (c) The baseline can be provided by the battery manufacturer or the test equipment OEMs.
2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5.</td></tr>
<tr><td>South Carolina Electric and Gas</td><td>R1.1 states “Identify all Protection System Components”. To avoid confusion this should be clarified. It could be interpreted that discreet components must be individually identified. An example would be as individual aux relays used in the tripping path.</td></tr>
<tr><td colspan="2">Response: Thank you for your comment. Requirement R1, Part 1.1, has been revised to state, “Address all Protection System component types”.</td></tr>
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PacifiCorp	1. R1.1: Please clarify what the requirements for "identify" means. Does each component need to be "identified" in our maintenance system, or at least referenced in the maintenance program or labeled in the field??? 2. R4.3: Please provide guidance on what will be required to prove compliance that "maintenance correctable issues" have been identified and corrective actions initiated. 3. What is the implication of finding maintenance correctable issues as it relates to other requirements for no single points of failure? In other words, if during maintenance a relay is found to have failed, is there an acceptable time period under which we may operate the system without redundancy until a repair can be made? Similarly, if part of a redundant relay system is taken out of service for maintenance, may the facility it was protecting be left in service? If not, then is the implication that protection systems must be triple redundant in order to do relay maintenance on in service equipment? Otherwise facilities would always have to be removed from service to do relay maintenance. 4. Section D / 1.3: The data retention requirement for the two most recent performances of each maintenance activity is excessive. The requirement should be limited to the most recent or all activities since the last on-site audit. At the worse case an entity would have to retain records for up to 35 years for maintenance performed on a 12 year cycle. 5. Table 1a "Protective Relay" entry: The last maintenance activity is listed as "for microprocessor relays verify acceptable measurement of power system input values " for which a 6 year interval is provided". How is this different than the next item "Voltage and Current Sensing Inputs to Protective Relays and associated circuitry" which is on a 12 year interval?? Please clarify this. 6. Implementation Plan: This revised standard will drive significant revisions in existing maintenance programs. 3 months is not adequate time after approval to ensure compliance with R1. A minimum of 6 months should be utilized after regulatory approval. The Implementation plan requirements should also recognize that if the requirement to maintain records of the two previous maintenance tasks is implemented, it may not be possible to produce this information upon implementation. The implementation plan should be structured that the requirement to produce previous maintenance records should be phased in as the maintenance is performed. (ie. The requirement to produce two

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<tr><td></td><td>previous records for maintenance performed on a two year cycle should not be enforced until four years after implementation).</td></tr>
<tr><td colspan="2">Response: Thank you for your comments.
1. Requirement R1, Part 1.1, has been revised to state, “Address all Protection System component types”.
2. Various means may be used. One suggestion would be work orders that addressed the issue.
3. It is left to the entity to determine HOW to address maintenance-correctable issues. It is reasonable that an entity would do so in a manner that presents the least disruption to the system and considers the impact of the malfunctioning component on reliability.
4. In order that a Compliance Monitor can be assured of compliance, the SDT 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, as well as data to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The SDT has specified the data retention in the posted Standard to establish this level of documentation. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-1.
5. The Implementation Plan for Requirement R1 had been revised from 3 months to 12 months.</td></tr>
<tr><td>Springfield Utility Board</td><td>SUB is supportive of the intent behind the standard and appreciates the ability to provide input into this process.

1.The following is a repeat of the comment in Question #5 with regard to the supplemental reference.

SUB appreciates that Time Based, Performance Based, and Condition Based programs can be combined into one program. However it should be clear that a utility may include one, two or all three of these types of programs for each individual device type.

Currently the language reads:"TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System." The "and" requires all three to be combined if they are combined. SUB suggests the “and” be changed to "or" language.

Change:"TBM, PBM, or CBM can be combined for individual components, or within a complete Protection System."</td></tr>
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Response: Thank you for your comments. Please see our response to your comment in Question 5.	
The Detroit Edison Company	1. Suggest that the implementation plan for R1 (PSMP) be changed to 12 months. 2. The statement in R1.1, "Identify all Protection System components" regarding the PSMP should be clarified. Is a complete list of every "component" of each specific protection system required to be included in the PSMP?
Response: Thank you for your comments. 1. The Implementation Plan for Requirement R1 has been revised from 3 months to 12 months. **2.** Requirement R1, Part 1.1, has been revised to state, "Address all Protection System component types."	
Long Island Power Authority	1. Table 1a under Maintenance Activities for Control and trip circuits with unmonitored solid-state trip or auxiliary contacts (UFLS/UVLS Systems Only) states: Perform a complete functional trip test that includes all sections of the Protection System control and trip circuit, including all solid-state trip and auxiliary contacts (e.g. paths with no moving parts), devices, and connections essential to proper functioning of the Protection System., except that verification does not require actual tripping of circuit breakers or interrupting devices. The word complete may be removed as it requires actually tripping the breakers. The sentence that tripping of the circuit breakers is not required contradicts with the word complete. 2. More specifics are required to spell out the adequate testing e.g. up to the lockout with the trip paths isolated etc. 3. Table 1a under Maintenance Activities for Station dc Supply (used only for UVLS or UFLS) states: Verify proper voltage of the dc supply. Is this requirement applicable to the distribution substations only? 4. Table 1a under Maintenance Activities for Station dc supply (battery is not used) - states Verify that the dc supply can perform as designed when the ac power from the grid is not present. - Please clarify this requirement.

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	5. Table 1a for Associated communications systems - specify the group for the applicability of this requirement. BPS,BES,UFLS etc. 6. Table 1a under Maintenance Activities for Associated communications systems states - Verify that the performance of the channel meets performance criteria, such as via measurement of signal level, reflected power, or data error rate. Why is this required? The requirement "Verify proper functioning of communications equipment inputs and outputs that are essential to proper functioning of the Protection System. Verify the signals to/from the associated protective relays seems sufficient to ensure reliability. 7. Table 1a under Maintenance Activities for Relay sensing for Centralized UFLS OR UVLS systems UVLS and UFLS relays that comprise a protection scheme distributed over the power system states: Perform all of the Maintenance activities listed above as established for components of the UFLS or UVLS systems at the intervals established for those individual components. The output action may be breaker tripping, or other control action that must be verified, but may be verified in overlapping segments. A grouped output control action need be verified only once within the specified time interval, but all of the UFLS or UVLS components whose operation leads to that control action must each be verified. Clarify what is meant by overlapping segments? What is the specified interval? Is actual breaker tripping required?

Response: Thank you for your comments.

1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5.
2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4.
3. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4.
4. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4.
5. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-3.
6. Communications systems are subject to a variety of problems. The listed activities will detect many of these problems. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-2.
7. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-1. Please see Section 8 of

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	the Supplementary Reference document regarding "overlapping segments."
American Electric Power	1. The "Supplementary Reference" and the "Frequently-Asked Questions" document should be combined into a single document. This document needs to be issued as a controlled NERC approved document. AEP suggests that the document be appended to the standard so it is clear that following directions provided by NERC via the document are acceptable, and to avoid an entity being penalized during an audit if the auditor disagrees with the document's contents. 2. NiCAD batteries should not be treated differently from Lead-Acid batteries. NiCAD battery condition can be detected by trending cell voltage values. Ohmic testing will also trend battery conditions and locate failed cells (although will usually lag behind cell voltages). A required load test is detrimental to the NiCAD manufacturer's business, and will definitely hurt the NiCAD business for T&D applications. Historically NiCADs may have been put into service because of greater reliability, smaller space constraints, and wider temperature operation range."Individual cell state of charge" is a bad term because it implies specific gravity testing. Specific gravity cannot be measured automatically (without voiding battery warranty or using an experimental system), and when it is measured, it is unreliable due to stratification of the electrolyte and differing depths of electrolyte taken for samples. "Battery state of charge" can be verified by measuring float current. Once the charging cycle is over the battery current drops dramatically, and the battery is on float, signaling that the battery has returned to full state of charge. This is an appropriate measure for Level 3 monitoring as float current monitoring is a commercially viable option and electrolyte level monitoring is not. 3. In Table 2b, why is Ohmic testing required if the battery terminal resistance is monitored? Cell to cell and battery terminal resistance should not be monitored because they will be taken in 18 month intervals. This further supports the argument that the battery charger alarms would be sufficient for level 2 monitoring, while keeping an 18 month requirement for Ohmic testing, electrolyte level verification, and battery continuity (state of charge). Automatic monitoring of the float current should be sufficient for level 3 monitoring as it gives state of charge of the string, and battery continuity (detect open cells). Shorted cells will still be found during the Ohmic testing and a greater interval is sufficient to locate these problems.

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Response: Thank you for your comments. 1. The SDT disagrees that the documents should be combined. The Supplementary Reference is a holistic presentation of rationale and basis for the various elements of the Standard – discussing mostly the "what" behind the requirements. The FAQ, on the other hand, presents responses to specific frequently-asked questions, and, as such, offers more-focused advice on specific subjects, and is more of a how-to/example discussion. The FAQ is primarily a means of capturing some of the most prevalent comments offered on the Standard by various entities, with the SDT's response. The SDT believes that the format of the FAQ is a more effective means of presenting the included information than it would be to include this information within the text of the Supplementary Reference document. The Standards Committee has a formal process for determining whether to authorize posting a reference document with an approved standard. That process is posted on the Standard Resources web page – here is a link to the procedure: http://www.nerc.com/files/SC_Process_Approve_Supporting_References_Approved_10Mar08.pdf 2. The SDT believes that, since the IEEE Stationary Battery Committee has determined that VRLA batteries and Ni-Cad batteries are different enough to require separate IEEE Standards (IEEE 1188 and IEEE 1106, respectively), these battery technologies are different enough to be treated separately within PRC-005-2. The SDT has drawn upon these IEEE Standards, as well as other sources (EPRI, etc) to develop the Requirements of PRC-005-2. The trending activity cited has not been shown to be effective for Ni-Cad batteries (see FAQ II.5.G), and thus a performance tests must be performed; the performance test may take many forms. The Tables have been rearranged and considerably revised to improve clarity, and all references to specific gravity have been removed. Please see new Table 1-4. Determining the "state of charge" by monitoring the float voltage may be relevant to the overall station battery, but does not provide an indication of the condition of individual cells as required within the new Table 1-4. 3. Battery terminal resistance shows the condition of the external connections, but reveals nothing regarding the internal condition of the individual cells. Measuring the internal cell/unit resistance provides an opportunity to trend the cell condition over time by verifying the electrical path through the electrolyte within the battery. The ohmic testing is not intended to look for open cells/units, but instead at the ability of the individual cell/unit to perform properly. The new Table 1-4 clarifies that, if the electrolyte level is monitored, the internal ohmic testing need only be performed every six years. Please see FAQ II.5.B, II.5,C, and II.5.D for a discussion about continuity.	
JEA	The current interpretation by the SDT of partially monitored is set at a higher bar than most utilities use in their current designs today. We all wish to take advantage of the microprocessor relays and their renowned and improved monitoring capability. If TC1 is monitored by primary relay A and TC2 is

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<tr><th>Organization</th><th>Question 7 Comment</th></tr>
<tr><td></td><td>monitored by primary relay B, and these relays in turn monitor their DC supplies, the vast majority of the system is monitored - (partially monitored), including all the control cable out to the remote breakers and their trip coils. To add to this some additional contacts within the scheme, located very near the primary relays, is extending the partially monitored bar to a higher level than most designs incorporate today. If you know that 98% of the DC control system is monitored - isn't that partially monitored? Please consider changes to the SDT's current view of a partially monitored protection systems.</td></tr>
<tr><td colspan="2">Response: Thank you for your comments. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5.</td></tr>
<tr><td>Arizona Public Service Company</td><td>1. The generator Facilities subsections 4.2.5.1 through 5 are too prescriptive and inconsistent with sections 4.2.1 through 4. Recommend this section be limited to description of the function as in the preceding sections.
2. Clarification is needed on how the “Note 1” in Table 1a, which appears to be used in to define a calibration failure would be used in Time Based Maintenance. In PRC-005-2 Attachment A: Criteria for a Performance-Based Protection System Maintenance Program, a calibration failure would be considered an event to be used in determining the effectiveness of Performance Based Maintenance. It is unclear in how it will be used in time based maintenance.</td></tr>
<tr><td colspan="2">Response: Thank you for your comments.
1. The SDT believes that transmission lines, UFLS, UVLS, and SPS are clear without additional granularity, but that the additional granularity regarding generation plants is necessary. This is illustrated by numerous questions regarding “what is included for generation facilities?” relative to PRC-005-1.
2. The Tables have been rearranged and considerably revised to improve clarity. In addition, the Note was removed, and Requirement 4 has been considerably revised.</td></tr>
<tr><td>Pacific Northwest Small Public Power Utility Comment Group</td><td>1. The level 2 table regarding Protection Station dc supply states that level 1 maintenance activities are to be used, but then goes on to give a list of Maintenance Activities that don’t match those in level 1. Which activities shall we use? Same situation for Station DC Supply (battery is not used) where the</td></tr>
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	18 month interval is missing. 2. IEEE battery maintenance standards call for quarterly inspections. These are targets, though, not maximums. An entity wishing to avoid non-compliance for an interval that might extend past three calendar months due to storms and outages must set a target interval of two months thereby increasing the number of inspections each year by half again. This is unnecessarily frequent. We suggest changing the maximum interval for battery inspections to 4 calendar months. For consistency, we also suggest that all intervals expressed as 3 calendar months be changed to 4 calendar months. 3. We are concerned over R1.1, where all components must be identified, without a definition for the word component or the granularity specified. While the FAQ gives a definition, and allows for entity latitude in determining the granularity, the FAQ is not part of the standard. We believe this will allow REs to claim non-compliance for every three inch long terminal jumper wire not identified in a trip circuit path. We suggest that the FAQ definitions be included within the standard.
Response: Thank you for your comments. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. 2. The SDT disagrees. The entity should schedule routine inspections to complete the specified activities within the specified 3-month interval. 3. Requirement R1, Part 1.1, has been revised to state, “Address all Protection System component types.”	
PNGC Power	The level 2 table regarding Protection Station dc supply states that level 1 maintenance activities are to be used, but then goes on to give a list of Maintenance Activities that don’t match those in level 1. Which activities shall we use? Same situation for Station DC Supply (battery is not used) where the 18 month interval is missing.
Response: Thank you for your comments. The Tables have been rearranged and considerably revised to improve clarity.	
MRO’s NERC Standards Review Subcommittee	1. The NSRS does not support the existing 2nd Draft of PRC-005-2 Standard because it is our opinion

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(NSRS)	that: o There is a high probability that system reliability will be reduced with this revised standard. o The utility industry is in the business of keeping the lights on, but these requirements will force the industry to take customers out of service in order to fulfill these requirements. A possible solution is to increase the test intervals, set performance targets, test set on a basis of past performance, etc. o The number of unplanned outages due to human error will increase considerably. o The requirement of a complete functional trip test will reduce the level of reliability and all levels of the BES to include distribution systems. o Availability of the BES will be reduced due to an increased need to schedule planned outages for test purposes (to avoid unplanned outages due to human error). o To implement this standard, an entity will need to hire additional skilled resources that are not readily available. (May require adjustments to the implementation timeline.) o The cost of implementing the revised standard will approximately double our existing cost to perform this work. 2. Requests that relevant reliability performance data (based on actual data and/or lessons learned from past operating incidents, Criteria for Approving Reliability Standards per FERC Order 672) be provided to justify the additional cost and reliability risks associated with functional testing. 3. Under a Performance-Based Program, what happens if the population of components drops below 60 (as all will eventually)? Is there an implementation period to default to TBM? 4. Please clarify In R1, the statement “or are designed to provide protection for the BES” re-opens the argument about transformer protection or breaker failure protection for transformer high-side breakers tripping BES breakers being included in the transmission protection systems. 5. Also, for Table 1b “Verify that each breaker trip coil, each auxiliary relay, and each lockout relay is electrically operated within this time interval” should be changed from a 6 year interval to a 12 year interval similar to the relay input and outputs. Experience has shown that these both have very

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	similar reliability. 6. The standard as currently drafted raises concern as it relates to the identification of all Protection System components, particularly those with associated communications equipment. In the case of leased lines, a utility would be expected to maintain equipment they do not own. Recommend revising the standard to consider maintenance activities on a communications channel basis in which intermediate device functioning can be verified by sending a signal from one relay to another. 7. Clarification should be given as to the reason for stating control circuitry separately, such as in “Control and trip circuits”. As currently stated, this implies that close circuit DC paths are now subject to a protection system maintenance program when reclosing and closing of breakers have never before been considered part of a Protection System. 8. Statements 3 (For microprocessor relays, check the relay inputs and outputs that are essential to proper functioning of the Protection System.) and 6 (Verify correct operation of output actions that are used for tripping. in Table 1b for Protective Relays essentially address the same issue. Please clarify if these are addressing the same issue or not. If the purpose is to describe the functionality of the protection system, that should be covered under another section in the table, such as DC circuitry. 9. How one identifies a voltage and current sensing input is not well defined. In most cases, this should already be identified with the relay. Also, the scope of detail required is ambiguous. Would individual cables, terminal blocks, etc. need to be identified as would be implied by “associated circuitry”? Please clarify. The NSRS recommends that individual cables, terminal blocks, etc are not included in this program. 10. Recommend removing “proper functioning of” from the maintenance activities for voltage and current sensing inputs in Table 1b. A utility is not verifying the functionality of the signal(s), they are verifying the signals themselves. Any functioning of the signals, which is related to ensuring proper relay interpretation, would be covered under the protective relay section. 11. In general, has thought been put into the possibility of degrading reliability by implementing such a rigorous maintenance program? To implement such a program, the number of scheduled outages would greatly increase resulting in scheduling conflicts that will increase, as well as degrading

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	system conditions by taking lines, transformers, etc. out of service. Because of past design practices many of the requirements for maintenance will only be able to be performed by lifting wires to isolated trip paths. Potential error is introduced anytime a wire is lifted, especially numerous wires, by means of ensuring they are put back in the correct place. Redundancy is one thing that has been implemented in great detail throughout the history of protection systems to ensure that they work as intended. Diligent commissioning may need to be given its due credit.

Response: Thank you for your comments.

1. Thank you for your opinions.
2. The Standard does not preclude an entity from largely utilizing other methods of verification, although functional testing may be the easiest to achieve.
3. The entity must revert to TBM if the population falls below 60. There is no implementation period; the SDT believes that the annual PBM review will alert the entity that the population is nearing 60, and allow the entity to react to the diminishing component population accordingly.
4. This comment relates to your regional BES definition, not the Standard.
5. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. The SDT believes that mechanical solenoid-operated devices share performance attributes (and failure modes) with electromechanical relays and need to be tested at similar intervals. Performance-based maintenance is an option to increase the intervals if the performance of these devices supports those intervals.
6. The functional testing of the channel will verify that the communications system operates properly. If the communications system does not perform properly, the applicable entity is responsible to assure that it is restored to service; the physical actions to do so may have to be performed by other parties. Your suggested end-to-end test is one effective way of performing this maintenance; however, this is only one of several ways of doing this.
7. This component of the definition is stated to apply as “associated with protective functions” and thus excludes close/reclosing circuits. Please see FAQ II.1.A.
8. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-1.
9. This component of the Protection System definition is to generally include this functionality as a part of the Protection System. The

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detailed applicability of this component within PRC-005-2 is addressed within the Standard. The "protective relay" only addresses how the relay itself uses these signals, but does not address the concern regarding whether these signals are accurate. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-3. Requirement R1, part 1.1, has been revised to state, "Address all Protection System component types" to clarify that "individual cables, terminal blocks, etc." need not be discretely addressed. The definition has also been revised to remove "associated circuitry" from this portion. Please see FAQ II.3.A. 10. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-3. **11.** The SDT believes that performing these maintenance activities will benefit the reliability of the BES.	
Indiana Municipal Power Agency	1. The proposed effective date working is confusing and maybe incorrect. It looks like the second part of the paragraph refers to the additional maintenance and testing required by requirement 2 of the current version of PRC-005-1. PRC-005-2 will be adding additional maintenance and testing. Since the current wording is confusing, we are not sure when we have to ensure the new testing is done on the protection equipment. 2. When it comes to battery maintenance, the battery cell to cell connection resistance has to be verified. IMPA is not sure how the SDT wants this maintenance performed. Some battery banks are made up of individual battery cases with two posts at each end that contain two to four individual battery cells inside of each case. To actually tear down the individual cells in a case would be extremely hard and maybe impossible on the sealed cases without destroying the cases. It would be nice to describe how the SDT wants the connection resistance of battery cell to cell verified in the FAQ guide. 3. In the same guide, the SDT might give insight on what is meant by verifying the state of charge of the individual battery cell/units (table 1A). It seems like measuring the voltage level of the individual battery would work for this verification, but additional information of what the SDT wants for this verification would eliminate any doubt and help with being in compliant with this requirement.
Response: Thank you for your comments. 1. The SDT does not understand your concern. Perhaps you are referring to the Implementation Plan for the definition rather than the Implementation Plan for the Standard. The second bullet in the introductory portion of the Implementation Plan for the Standard has	

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<tr><td colspan="2">been modified to state, " ... is being performed according to …" rather than "has been moved to" to be more concise.
2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. The term "cell" has been modified to "cell/unit" to address part of your concern. Please see FAQ II.5.L.
3. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. IEEE Standards 1188, 450, and 1106 provide "how-to" guidance specific to various battery technologies.</td></tr>
<tr><td>ReliabilityFirst Corp.</td><td>The SDT should be congratulated on its hard work in making substantial improvements to an existing standard.
1. In revising the draft standard, the SDT should consider the difficulty an entity will have in providing the evidence required to show compliance.
2. R1 unnecessarily limits PSMPs to "Protection Systems that use measurements of voltage, current, frequency and or phase angle to determine anomalies." However, if an entity applies devices that protect equipment based on other non-electrical quantities or principles such as temperature or changes in pressure, the entity is not required to maintain them. These types of devices have long been considered by many organizations as important forms of protection and therefore in some instances are connected to trip. There are also many organizations that consider these types of devices too unreliable to use as protection and therefore only connect them for monitoring (and not to trip). If protection based on non-electrical quantities is not properly maintained, it will Misoperate and will negatively impact reliability. The standard cannot simply ignore a type of protection that can ultimately affect the reliability of the BES.</td></tr>
<tr><td colspan="2">Response: Thank you for your comments.
1. The SDT has considered this, and has provided examples in the Measures. Please see Section 15.7 of the Supplementary Reference document and FAQ IV.1.B.
2. Requirement R1 does not preclude entities from maintaining such devices or including them in the PSMP.</td></tr>
<tr><td>Indeck Energy Services</td><td>The standard should include an assessment of, and criteria for, determining whether a Protective System is important to reliability. It presently treats a fault current relay on a 345 kV or higher voltage</td></tr>
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	transformer the same as one on a small generator on the 115 kV system. The impact of failures on both on a hot summer day like we've had recently in NY, would be very different. As discussed at the FERC Technical Conference on Standards Development, the goal of the standards program is to avoid or prevent cascading outages--specifically not loss of load. This seems to have been lost in the drafting process. Much of the effort expended on complying with the existing PRC maintenance standards, as well as that to be expended on PRC-005-2, has little to no significant in terms of improving reliability. That effort could be better utilized if focused on activities that could significantly improve reliability. As one of the Commissioners at the FERC Technical Conference on Standards Development characterized the relationship between FERC and NERC as a wheel off the track. The whole standards program, and especially PRC-005-2, is off the track.
Response: Thank you for your comments. Your comments seem to be related to NERC Standards Development in general, and to BES definitions. The 2007-17 SDT is unable to address these concerns. The SDT is addressing its assignment from the approved SAR, and believes that performing maintenance on Protection Systems will benefit the reliability of the BES.	
US Bureau of Reclamation	1. The sub-requirements for R1, are not criteria, rather implementation requirements more suitable to be included in R4. Examples of what the PSMP shall address which would be more consistent with the language in R1 would be: • How are changes to the PSMP administered? • Who approves the determination of the use of time-based, condition based or performance based maintenance. • Who reviews activities under the PSMP 2. References used within the standard are not consistent. In R1.2 Attachment as is referred to as Attachment A. In R3 Attachment A is referred to as PRC-005 Attachment A. This implies a difference. Under a voluntary world, we could draft criteria and procedures with these problems and interpret them correctly. Today in the compliance world, the language must be precise and unambiguous. The reference must be the same it means something different. 3. The requirement in R1, which is consistent with the purpose, does not support the applicability in

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	R4.2.5.4. Protection systems associated with stations service are not designed to provide protection for the BES. In particular we have been told that intent was not to look at every device that tripped the generator but devises that sensed problems on the BES and trip the generator. Hence we include such things as frequency relays, Differential relays, zone relays, over current, and under voltage relays. Even a loss of field looks at the system as included. Speed sensing devices were explicitly excluded. As such, if the stations service transformer protection looks toward the BES (e.g. differential relays and zone relays) they would be included. Over current would not as it would be on the station side. If a Station Service transformer saw excess current, the system would in most cases fail over to other side. If not, it would cause the generator to trip much like a generator thermal device which is also excluded. Maintenance programs offer a unique problem to the FERC and regulatory world. The knee jerk reaction is to define them. What happens if the solution is bad, who will accept the consequences that narrow prescription was wrong and the interval caused a reliability impact. It would no longer be the Entity. History is replete with examples of this type of micro managing. Rather than fall into the same trap, and suffer the consequences of the unknown, allow Entities to optimize their programs to ensure reliability of the BES and create a standard of disallowed practices which have a demonstrated impact on reliability.
Response: Thank you for your comments. 1. Requirement R1 presents the requirements to establish a PSMP; Requirement R4 presents the implementation of the program. The SDT believes that this arrangement is correct. The examples cited seem to be related more to the internal administration of the PSMP within an entity, and not to the requirements. 2. The Standard has been modified to make these phrases consistent in consideration of your comment. 3. The SDT believes that the station service transformers may be essential to the operation of the generator (which is the BES element), and thus that the protection of these needs to be addressed as part of PRC-005-2.	
Bonneville Power Administration	1. The term “maintenance correctable issue” used in Requirement 4 seems to be at odds with the definition given for it. It seems that an issue that cannot be resolved by repair or calibration during the maintenance activity would be a maintenance non-correctable issue. Also, in Requirement 4, the term “identification of the resolution” is ambiguous. Suggested changes for Requirements 4 and 4.1

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	are: a. R4. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement its PSMP, and resolve any performance problems as follows: b. 4.3 Ensure either that the components are within acceptable parameters at the conclusion of the maintenance activities or initiate actions to replace the component or restore its performance to within acceptable parameters.
Response: Thank you for your comments. **1.** The definition of "maintenance correctable issue" is consistent with the way it is used within the Standard.	
Santee Cooper	There is some discussion in the documents, such as the definition of component in the Frequently-Asked Questions, about the idea that an entity has some latitude in determining the level of "protection system component" that they use to identify protection systems in their program and documentation. The example given is about DC control circuitry. There are requirements in this standard that are specific to a component, such as R1.1 - Identify all protection system components. Historically, if your maintenance and testing program is defined as (say, for relays) testing all the relays in a station at one time, your program, test dates, etc. could be identified by the station. There needs to be some addition, possibly to the Frequently asked questions, to explain what kind of documentation will be required with this new standard. For example, if your program is to test all the relays at a station every 4 years, and all the relays are tested at the same time, can your documentation of your schedule (the "date last tested" and previous date) be listed by station (accepting that you should have the backup data to show the testing was thorough) or must you be able to provide a list by each relay. Without some clarification, it seems like this could get confusing at an audit with many of the requirements pertaining to "each component."
Response: Thank you for your comments. Requirement R1, Part 1.1, has been revised to state, "Address all Protection System component types." The remaining issues within your comment are dependent on how your PSMP addresses them.	
Northeast Power	1. UFLS systems by design can suffer random failures to trip. A requirement should exist that stipulates to perform maintenance on the UFLS relay as their failure to operate may affect numerous

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Coordinating Council	distribution level feeders. However maintenance on associated DC schemes connected to the devices should only be done on the same frequency as maintenance on the relevant interrupting devices. Consideration should be given to exempting schemes that have a maintenance program in place on those distribution level devices from PRC-005 Standard-specified maintenance intervals. Such Standard-specified intervals could apply to interrupting devices that have no maintenance program in place. 2. This standard is overly prescriptive. Owners of protection system equipment establish maintenance procedures and timelines based on manufacturers' recommendations and experiences to ensure reliability. Maintenance intervals change with improved practices and equipment designs, and whenever that occurs PRC-005 will have to go through the revision process, which would be frequent and unnecessary if the standard were more general.
Response: Thank you for your comments. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5. 2. FERC Order 693 and the approved SAR for this project directed the SDT to establish both maximum maintenance intervals and minimum maintenance activities within the revised Standard.	
Entergy Services	We support this project and believe it is a positive step towards BES reliability. However, we believe the draft document needs additional work as per our comments. Also, as indicated by the amount of industry input on the last version draft comments, we believe revisions are still needed to properly address this technically complex standard. If this standard is to deviate from the original project schedule and follow a fast track timeline for approval, then we disagree with the 3 month implementation for Requirement 1 and ask for at least 12 months. The original schedule provided sufficient advance notice to work on an implementation plan and it included the typical time required for NERC Board of Trustees and regulatory approvals. If the project schedule and typical NERC Board of Trustees and regulatory approval times are to be accelerated, the implementation plan should be extended.
Response: Thank you for your comments. The Implementation Plan for Requirement R1 has been revised from 3 months to 12	

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months.	
Utility Services	With regard to DPs who own transmission Protection Systems, the standard is still very unclear on when a DP owns a transmission Protection System. Many DPs own equipment that is included within the definition of a Protection System; however, ownership of such equipment does not necessarily translate directly into a transmission Protection System under the compliance obligations of this standard. DPs need to know if this standard applies to them and right now, there is no certain way of determining that from within this language or previous versions of this standard. Additionally, the NPCC Regional Standards Committee withdrew a SAR on this very subject as we informed the question would be addressed in this proposal.
Response: Thank you for your comments. Your concern seems to be primarily related to the applicable regional BES definition.	
Y-W Electric Association, Inc.	1. Y-WEA concurs with Central Lincoln regarding the timing of required battery tests. The IEEE standards referenced indicate target maintenance intervals. In order to remain reasonable, then, this compliance standard needs to allow some buffer between a targeted maintenance and inspection interval and a maximum enforceable maintenance and inspection interval. Central Lincoln's suggestion of a four-month maximum window is reasonable and should be incorporated into the standard. 2. Y-WEA is also concerned with R1.1's language indicating that all components must be identified with no defined "floor" for the significance of a component to the Protection System. The SDT cannot possibly expect that a parts list containing every terminal block, wire and jumper, screw, and lug is going to be maintained with every single part having all the compliance data assigned to it, but without clearly stating this, that is exactly the degree of record-keeping that some overzealous auditor could attempt to hold the registered entity to. The FAQ is much clearer as to what is and is not a component and should be considered for the standard. 3. Y-WEA also concurs with FMPA's comments regarding the testing of batteries and DC control circuits associated with UFLS relaying. Many UFLS relays are installed on distribution equipment. Furthermore, many distribution equipment vendors are including UFLS functions in their distribution equipment. For example, many recloser controls incorporate a UFLS function in them. These

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	controls and the reclosers they are attached to, however, are strictly distribution equipment. 16 USC 824o (a)(1) limits the definition of the Bulk-Power System to "not include facilities used in the local distribution of electric energy." A distribution recloser and its control clearly fall into this exclusion. 16 USC 824o (i)(1) prohibits the ERO from developing standards that cover more than the Bulk-Power System. As such, the DC control circuitry and batteries associated with many UFLS relaying installations are precluded from regulation under NERC's reliability standards and may not be included in this standard because they are distribution equipment and therefore not part of the Bulk-Power System. The proposed standard needs to be rewritten to allow for this exclusion and to allow for the testing of only the UFLS function of any distribution class controls or relays.

Response: Thank you for your comments.

1. The SDT disagrees. You should complete the activities within the intervals specified.
2. Requirement R1, Part 1.1, has been revised to state, "Address all Protection System component types."
3. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-4 and 1-5.