Consideration of Comments on Protection System Maintenance [Project 2007-17]

The Protection System Maintenance Drafting Team thanks all commenters who submitted comments on the 3rd draft of the standard for Protection System Maintenance and Testing. These standards were posted for a 30-day public comment period from November 17, 2010 through December 17, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 44 sets of comments, including comments from more than 81 different people from approximately 82 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

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

Extensive changes were made to Requirements R1 and R3 of the Standard, and also to the Tables referenced within the Requirements. Of particular note, Requirement R1, Part 1.5 (which required entities to define their acceptance criteria for maintenance of components), and the associated discussion within Requirement R4, Part 4.2 were removed. Requirement R2 was removed because it was duplicative of Requirement R1, Part 1.4. Also, Table 1-4, addressing maintenance of Station DC Supply, was split into six separate sub-tables addressing the various specific technologies within this component.

Some commenters continued to object to various requirements within the standard. Where the standard was not revised in response to these comments, the SDT explained their rationale within the consideration-of-comments.

Based on the level of consensus on this posting, the SDT will post the Standard and associated documents for an additional 30-day comment period with concurrent ballot in the final 10-days of that comment period.

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, Herb 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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	David K Thorne	Pepco Holding Inc & Affilates	X									

Additional Member	Additional Organization	Region	Segment Selection	
1.	Carlton Bradshaw		RFC	1
2.	Carl Kinsley		RFC	1
3.	Bob Reuter		RFC	3
4.	Mike Mayer		RFC	3
5.	Jim Petrella		RFC	3

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Russell Noble	Cowlitz County PUD No. 1	WECC	3, 4, 5
2.	Dave Proebstel	Clallam County PUD	WECC	3
3.	Ronald Sporseen	Blachly-Lane Electric Cooperative	WECC	3
4.	Ronald Sporseen	Central Electric Cooperative	WECC	3
5.	Ronald Sporseen	Consumers Power	WECC	3

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

6.	Ronald Sporseen	Clearwater Power Company	WECC	3
7.	Ronald Sporseen	Douglas Electric Cooperative	WECC	3
8.	Ronald Sporseen	Fall River Rural Electric Cooperative	WECC	3
9.	Ronald Sporseen	Northern Lights	WECC	3
10.	Ronald Sporseen	Lane Electric Cooperative	WECC	3
11.	Ronald Sporseen	Lincoln Electric Cooperative	WECC	3
12.	Ronald Sporseen	Raft River Rural Electric Cooperative	WECC	3
13.	Ronald Sporseen	Lost River Electric Cooperative	WECC	3
14.	Ronald Sporseen	Salmon River Electric Cooperative	WECC	3
15.	Ronald Sporseen	Umatilla Electric Cooperative	WECC	3
16.	Ronald Sporseen	Coos-Curry Electric Cooperative	WECC	3
17.	Ronald Sporseen	West Oregon Electric Cooperative	WECC	3
18.	Ronald Sporseen	Pacific Northwest Generating Cooperative	WECC	5
19.	Ronald Sporseen	Power Resources Cooperative	WECC	3

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rusty Hardison	TOM Support	SERC	NA
2.	Paul Baldwin	TOM Support	SERC	NA
3.	David Thompson	Hydro Production Engineering	SERC	NA
4.	Frank Cuzzort	Nuclear Engineering	SERC	NA
5.	Robert Mares	Fossil Engineering		NA

				1	2	3	4	5	6	7	8	9	10
4.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Al Adamson	New York State Reliability Council, LLC		10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chang	Independent Electricity System Operator	NPCC	2
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1

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

6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Dean Ellis	Dynegy Generation	NPCC	5
8.	Brian Evans-Mongeon	Utility Services	NPCC	8
9.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	Chantel Haswell	FPL Group, Inc.	NPCC	5
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Michael R. Lombardi	Northeast Utilities	NPCC	1
15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	Saurabh Saksena	National Grid	NPCC	1
21.	Michael Schiavone	National Grid	NPCC	1
22.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

				1	2	3	4	5	6	7	8	9	10
5.	Group	Deborah Schaneman	Platte River Power Authority System Maintenance	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Scott Rowley	Platte River Power Authority	WECC	1, 3, 5, 6
2.	Gary Whittenberg	Platte River Power Authority	WECC	1, 3, 5, 6
3.	Aaron Johnson	Platte River Power Authority	WECC	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
6.	Group	Mike Garton	Electric Market Policy	X		X		X	X				
7.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
8.	Group	Terry L. Blackwell	Santee Cooper	X		X		X	X				
9.	Group	Mallory Huggins	NERC Staff										
10.	Group	Sam Ciccone	FirstEnergy	X		X		X	X				
11.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X	X			
12.	Group	Kenneth D. Brown	PSEG Companies ("Public Service Enterprise Group Companies")	X		X		X	X				
13.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X
14.	Individual	Brandy A. Dunn	Western Area Power Administration	X									
15.	Individual	Joanna Luong-Tran	TransAlta Centralia Generation Partnership					X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
16.	Individual	Silvia Parada Mitchell	NextEra Energy	X		X		X	X				
17.	Individual	Reza Ebrahimian	City of Austin DBA Austin Energy				X						
18.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
19.	Individual	JT Wood	Southern Company Transmission	X		X							
20.	Individual	Jack Stamper	Clark Public Utilities	X									
21.	Individual	John Bee	Exelon	X				X					
22.	Individual	Joe Petaski	Manitoba Hydro	X		X		X					
23.	Individual	Dan Roethemeyer	Dynegy Inc.					X					
24.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
25.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
26.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
27.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
28.	Individual	Ed Davis	Entergy Services	X		X		X	X				
29.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
30.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
31.	Individual	Dan Rochester	Independent Electricity System Operator		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
32.	Individual	Thad Ness	American Electric Power	X		X		X	X				
33.	Individual	Michael Moltane	ITC	X									
34.	Individual	Kathleen Goodman	ISO New England Inc.		X								
35.	Individual	Rick Koch	Nebraska Public Power District	X		X		X					
36.	Individual	Armin Klusman	CenterPoint Energy	X									
37.	Individual	Andrew Pusztai	American Transmission Company	X									
38.	Individual	Eric Salsbury	Consumers Energy			X	X	X					
39.	Individual	Bill Shultz	Southern Company Generation	X		X		X	X				
40.	Individual	Martin Bauer	US Bureau of Reclamation					X					
41.	Individual	Kenneth A. Goldsmith	Alliant Energy				X						
42.	Individual	Martyn Turner	LCRA Transmission Services Corporation	X									
43.	Individual	Terry Harbour	MidAmerican Energy	X		X		X	X				
44.	Individual	Kirit Shah	Ameren	X		X		X	X				

1. **The SDT has restructured the tables to improve clarity, but did not appreciably change the content. Do you agree that the restructured tables are clearer? If not, please provide specific suggestions for improvement.**

Summary Consideration: Generally, commenters indicated that the rearrangement of the Tables was beneficial. Several commenters questioned the arrangement of Table 1-4 and the SDT responded by revising this Table. A few commenters suggested further rearrangement of the Tables; the SDT observed that there are many potential ways to organize the Tables and declined to adopt these suggestions. The SDT made minor changes to Table 1-3 and Table 2 verbiage based on stakeholder comments.

Organization	Yes or No	Question 1 Comment
Pepco Holding Inc & Affiliates	Yes	
Pacific Northwest Small Public Power Utility Comment Group	Yes	
Tennessee Valley Authority	Yes	
Northeast Power Coordinating Council	No	The wording “Component Type” is not necessary in each title. Just the equipment category should be listed--what is now shown as “Component Type - Protective Relay”, should be Protective Relay. However, Protective Relay is too general a category. Electromechanical relays, solid state relays, and microprocessor based relays should have their own separate tables. So instead of reading Protective Relay in the title, it should read Electromechanical Relays, etc. This will lengthen the standard, but will simplify reading and referring to the tables, and eliminate confusion when looking for information. The “Note” included in the heading is also not necessary. “Attributes” is also not necessary in the column heading, “Component” suffices.
Response: Thank you for your comments. The SDT believes that the table headings are appropriate as reflected in the draft standard.		
Platte River Power Authority System Maintenance	Yes	
Electric Market Policy	Yes	Dominion does not feel that clarity has been added to the tables. 1. A numbering structure should be added to the table for referencing each task prescribed.

Organization	Yes or No	Question 1 Comment
		2. The tables should more clearly designate and separate time based versus performance based tasks. 3. Additionally, Table 1-4 contains, in several places, an activity to "Verify that the station battery can perform as designed by evaluating the measured cell/unit internal ohmic values to station battery baseline." This seems to suggest that each time the batteries are checked, the measured cell/unit internal ohmic value should agree with some baseline value. This appears to be overly prescriptive as the values reading-to-reading should fall within the tolerances established per Requirement R1.5, not equal a baseline. The activities for other component types are not this prescriptive.
Response: Thank you for your comments. **1. The SDT believes that numbering the tasks within the Tables as you suggest would make the Tables more complex and would not add clarity.** **2. Performance-based maintenance requires that the same tasks be completed, but at intervals determined per Attachment A.** **3. The station battery baseline value is up to the entity to determine. Please see Section 15.4.1 of the Supplementary Reference for a discussion of this. The SDT has determined that the fundamental concerns of R1 part 1.5 and the associated changes are addressed within the PSMP definition, and that R1 part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.**		
Bonneville Power Administration	Yes	
Santee Cooper	Yes	
NERC Staff	Yes	
FirstEnergy	Yes	While we agree that the clarity of the tables has improved, there are still items that warrant further clarity. 1.In Table 1-1, references to "Verify acceptable measurement of power system input values" is made for microprocessor relays on 6 and 12 calendar year intervals. Wouldn't this also be prudent on non-microprocessor based relays as well on the 6 year interval? 2. Also, in Table 1-3, "Verify that acceptable measurement of the current and voltage signals are received by the protective relays" is shown on a 12 calendar year interval. What is the difference between this activity and the similar activity performed in Table 1-1? 3. In Table 1-4, this table is complex and the detailed maintenance activities in this particular table is puzzling when compared to the more generic detail in the other tables within this section. For example, an incorrect operation due to a deteriorated signal from a CT or VT has a higher probability than a failure of a battery bank

Organization	Yes or No	Question 1 Comment
		to perform when called upon. 4. In Table 1-5, Please provide clarity on the "Unmonitored Control circuitry associated with protective functions" component attribute. This would most likely be an FAQ item.
Response: Thank you for your comments. **1. For non-microprocessor relays, this activity is fundamentally performed as a part of the calibration process.** **2. This activity is used to verify the performance of the voltage and current sensing devices, where the activity in Table 1-1 is used to verify that the protective relay is performing properly. In some cases, the activity in Table 1-1 may also serve to satisfy the requirement in Table 1-3.** **3. Table 1-4 is more detailed than the other tables because of the variability in the technologies of the station dc supply.** **4. The draft definition of Protection System establishes "Control circuitry" as "…control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices". Please see Section 15.3 of the Supplementary Reference for a discussion of this.**		
Florida Municipal Power Agency	Yes	
PSEG Companies ("Public Service Enterprise Group Companies")	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Western Area Power Administration	Yes	
TransAlta Centralia Generation Partnership	Yes	
NextEra Energy	Yes	
City of Austin DBA Austin Energy		
PacifiCorp	Yes	

Organization	Yes or No	Question 1 Comment
Southern Company Transmission	Yes	The Standard Drafting Team should be commended for making the tables much easier to understand
Response: Thank you for your support.		
Clark Public Utilities	No	The SDT has greatly improved the clarity of this document in the areas of relays, communication systems, voltage and current sensing devices, control circuitry, and alarming paths. The recommendations on station dc supply are still confusing. First, there are five different attribute categories for unmonitored dc supply. Are these five categories mutually exclusive? Are we supposed to follow just the category applicable to the type of battery? Are we supposed to follow the first category and any of the subsequent four battery type categories as they apply? I suspect some of the 3 month and 18 month items in the first category are considered to be necessary by the SDT regardless of battery type. The current categorization is confusing. If we are required to perform the 3 month and 18 month activities listed in the first category regardless of battery type AS WELL AS the other applicable battery type activities, please indicate this in Table 1-4. As a different option, just eliminate the first category entirely and place the appropriate 3 month and 18 month verification and inspection requirements in the four battery type specific categories. It may be repetitive but clarity is paramount in this standard. Second, the FAQ examples seem to indicate that the SDT views the performance of an internal ohmic battery test or a battery performance test as valid forms for verifying the individual battery cell states (i.e. state of charge of the individual battery cells/units, battery continuity, battery terminal connection resistance, and battery internal cell-to-cell or unit-to-unit connection resistance). It would be helpful if this were more obviously stated in table 1-4. Currently it could be interpreted that we need to do all of the individual cell-cell verification in addition to the ohm test or the full performance test. I don't believe this is the intent of the SDT (based on the FAQ examples) but we need to see the intent in Table 1-4.Third, does a monitored dc supply have to monitor some or all of each of the different line items listed? The FAQ examples indicate that if only some are monitored, the dc supply can still be treated as monitored as long as the unmonitored items are verified. This means that for a VLA battery with a low voltage alarm and unintentional ground alarm, all that is needed is to check electrolyte level every 3 months, check float voltage and battery rack every 18 months and perform either an internal ohm check at 18 months or a battery performance test at 6 years. Also battery alarms need to be verified at 6 years. This is not clear in Table 1-4 and it could be interpreted by some that a monitored station dc supply monitors ALL of the listed items not just SOME. The FAQs imply that partial monitoring is acceptable but Table 1-4 does not indicate this very clearly. I do wish to say once again that this proposed standard is much easier to understand and that with a little more clarification in the dc supply section I would vote in the affirmative.
Response: Thank you for your comments. Table 1-4 has been modified in consideration of your comments. Specifically, Table 1-4 has been revised to		

Organization	Yes or No	Question 1 Comment
remove "state of charge" from the activities.		
Exelon		
Manitoba Hydro	No	The maintenance requirements for batteries listed in Table 1-4 do not appear to be consistent with example 1 in Section V, 1A of the FAQ. Specifically the FAQ does not mention the state of charge of the individual battery cells/units, the battery continuity, the battery terminal connection resistance, the battery internal cell-to-cell or unit-to-unit connection resistance, or the cell condition, which are indicated as 18 month interval tasks in table 1-4.
Response: Thank you for your comments. The SDT decided to eliminate the FAQ document and incorporate the FAQ's contents into the Supplementary Reference Document as appropriate. The SDT considered your comments during this activity. Table 1-4 has been revised to remove "state of charge" from the activities.		
Dynegy Inc.	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ingleside Cogeneration LP	Yes	The tables clearly tie to each component type in a Protection System. This is consistent with the required PSMP format, making it straight forward to incorporate the intervals and to demonstrate compliance.
Response: Thank you for your support.		
Indiana Municipal Power Agency	Yes	
South Carolina Electric and Gas	Yes	
Entergy Services	No	The tables are generally much clearer and the SDT is to be commended on their efforts. However, we believe the Alarming Point Table needs additional clarification with regard to the Maximum Maintenance Interval. If an "alarm producing device" is considered to be a device such as an SCADA RTU, individual entity intervals for such a device would differ, and there isn't necessarily a maximum interval established as there is for Protection System components. Also, if an entity's alarm producing device maintenance is performed in sections and triggered by segment or component maintenance, there would essentially be multiple maximum intervals for the alarm producing

Organization	Yes or No	Question 1 Comment
		device of that entity. On that basis, we suggest the interval verbiage be revised to “When alarm producing device or system is verified, or by sections as per the monitored component/protection system specified maximum interval as applicable”. Alternately, if the intention is to establish maximum intervals as simply being no longer than the individual component maintenance intervals as we suggest for inclusion above, then the verbiage should be revised to “When alarm producing component/protection system segment is verified”. In either case are we to interpret monitored components with attributes which allow for no periodic maintenance specified as not requiring periodic alarm verification?
Response: Thank you for your comments. For clarity, the ‘Maximum Maintenance Interval’ column entry in Table 2 has been revised to state, “When alarm producing Protection System component is verified”.		
Duke Energy	Yes	
Wisconsin Electric Power Company	Yes	
Independent Electricity System Operator		
American Electric Power	No	1. Table 1.5 (Control Circuitry), row 4, indicates a maximum interval of 12 years for unmonitored control circuitry, yet other portions of control circuitry have a maximum interval of 6 years. AEP does not understand the rationale for the difference in intervals, when in most cases, one verifies the other. 2. Also, unmonitored control circuitry is capitalized in row 4 such that it infers a defined term. 3. In the first row of table 1-4 on page 16, it is difficult to determine if it is a cell that wraps from the previous page or is a unique row. This is important because the Maximum Maintenance Intervals are different (i.e. 18 months vs. 6 years). It is difficult to determine to which elements the 6 year Maximum Maintenance Interval applies. 4. AEP suggests repeating the heading “Monitored Station dc supply (excluding UFLS and UVLS) with: Monitor and alarm for variations from defined levels (See Table 2):” for the bullet points on this page.
Response: Thank you for your comments. **1. The 6-year activities are all related to components with “moving parts”, and the 12-year activities are related to the other portions of the control**		

Organization	Yes or No	Question 1 Comment
circuitry. **2. The capitalized term has been corrected.** **3. Table 1-4 has been modified in consideration of your comments.** **4. Table 1-4 has been modified in consideration of your comments.**		
ITC	Yes	The following question concerns Table 1-3. 1. Our testing program includes "impedance testing" of the current transformers (CTs) along with insulation testing of the wiring and CT secondary. Impedance testing involves impressing an increasing voltage on the secondary of the CT (with primary open circuited) until 1 (one) ampere flows. This method determines the "knee" of the saturation curve that is used as a benchmark for comparison to previous testing and other CTs. This procedure has successfully identified CT problems over the past several decades. We believe this procedure to be adequate. Does the SDT agree that this method is sufficient to meet the testing requirements of Table 1-3 and that a current comparison is not needed in addition to this testing? 2. Another variation of this is for voltage device compliance. Table 1-3 indicates that we should verify the correct voltages are received by the relay. This means that the VT would need to be energized and we would measure the secondary voltages to compare with others. Power plant relay testing is normally performed during plant outages when this measurement cannot be done. Some plants do not allow any testing while the unit is on line. It would seem that the standard would be written to allow some other type of testing to be performed other than the measurement test. 3. For Table 1-1 Row 1, we believe the intent is to verify that settings are as specified for non-microprocessor relays and microprocessor relays alike. If this is the case, consider adding "Verify that settings are as specified" as a bullet under the headings for non-microprocessor relays and microprocessor relays. 4. Splitting the tables into separate sections for Protective Relays, Communication Systems, VT and CTs, and Station D.C. Supply helped the clarity.
Response: Thank you for your comments. **1. Table 1-3 has been revised in consideration of your comments. Also, please see Section 15.3 of the Supplementary Reference Document. The SDT has decided to eliminate the FAQ and incorporate topics and discussion from the FAQ within the Supplementary Reference Document. Your comments will be considered within that activity.** **2. Table 1-3 has been revised in consideration of your comments. Also, please see Section 15.3 of the Supplementary Reference Document. The SDT has decided to eliminate the FAQ and incorporate topics and discussion from the FAQ within the Supplementary Reference Document. Your comments will be considered within that activity.**		

Organization	Yes or No	Question 1 Comment
3. "Verify that settings are as specified" is specified as an activity that applies to all Protective Relays, regardless of technology. The SDT has decided to eliminate the FAQ and incorporate topics and discussion from the FAQ within the Supplementary Reference Document. Your comments will be considered within that activity. **4. Thank you for your support.**		
ISO New England Inc.	No	The wording "Component Type" is not necessary in each title. Just the equipment category should be listed--what is now shown as "Component Type - Protective Relay", should be Protective Relay. However, Protective Relay is too general a category. Electromechanical relays, solid state relays, and microprocessor based relays should have their own separate tables. So instead of reading Protective Relay in the title, it should read Electromechanical Relays, etc. This will lengthen the standard, but will simplify reading and referring to the tables, and eliminate confusion when looking for information. The "Note" included in the heading is also not necessary. "Attributes" is also not necessary in the column heading, "Component" suffices.
Response: Thank you for your comments. The SDT believes that the table headings are appropriate as reflected in the draft standard.		
Nebraska Public Power District	Yes	
CenterPoint Energy	Yes	
American Transmission Company	Yes	
Consumers Energy	Yes	
Southern Company Generation	Yes	
US Bureau of Reclamation		No Comment
Alliant Energy	Yes	
LCRA Transmission Services Corporation	No	1. It would help to add a column to the left labeled Category. I.E. a relay could be classified under Category 1 attributes unmonitored or Cat 2, Cat 3. 2. Table 1-4, Station DC is very difficult to follow.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. **1. The SDT believes that the table headings are appropriate as reflected in the draft standard.** **2. Table 1-4 has been modified in consideration of your comments.**		
MidAmerican Energy	Yes	
Ameren	Yes	
Xcel Energy	Yes	

2. **The SDT has modified the VSLs, VRFs and Time Horizons with this posting. Do you agree with the changes? If not, please provide specific suggestions for improvement.**

Summary Consideration: Several commenters objected to the "percentage" steps in several VSLs. The SDT observes that the 'percentage' steps follow the VSL Guidelines which can be found on the NERC website in the 'Resource Documents' area of the 'Reliability Standards' section. Other commenters requested that the VSLs permit some level of non-compliance before incurring a 'Low' VSL, again the SDT notes that this is not acceptable per the VSL Guidelines.

Organization	Yes or No	Question 2 Comment
Pepco Holding Inc & Affiliates	Yes	
Pacific Northwest Small Public Power Utility Comment Group	Yes	
Tennessee Valley Authority	No	1. There is no allowance for deferral of maintenance because of factors beyond the control of the TO, GO, or DP. These include the unavailability of customer outages, generation outages, system configuration, high risk of loss of generation or customer load or impact to power quality. Proposed Change: Provide a process for acceptable deferral of maintenance activities. 2. Table 1-4 The requirement to perform cell internal ohmic resistance measurements every 18 months for vented lead-acid batteries is excessive. Our normal battery life is 20+ years. A 3-year internal resistance test frequency is adequate to prove battery integrity. IEEE 1188 recommends verification of internal ohmic resistance to be on a quarterly basis. It appears other intervals take into account recommended inspection interval plus some grace period. Proposed Change: Change maintenance interval from 3 months to 6 months. 3. Section: R1.5 This new requirement will require significant documentation with no known improvement to the reliability of the BES. What data is being used to determine the need for this requirement? How far does this requirement go? 4. Table 1-4 requires the inspection of "physical condition of battery rack" What are "identify calibration tolerance or other equivalent parameters" for this task? You already have verified, test, inspect, and calibrate defined. Leave out R1.5 which requires more than meeting the definitions.
Response: Thank you for your comments.		

Organization	Yes or No	Question 2 Comment
1. FERC Order 693 directs NERC to establish maximum allowable intervals. A "deferral process" would not satisfy this directive. **2. The SDT disagrees, and believes that 18-months is the proper interval for this activity.** **3. The SDT has determined that the fundamental concerns of R1 part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. Please see Supplementary Reference Document, Section 8 for a discussion of this. The associated VSL has also been revised.** **4. The SDT has determined that the fundamental concerns of R1 part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.**		
Northeast Power Coordinating Council	No	1. Because all the requirements deal with protective system maintenance and testing, violations could directly cause or contribute to bulk electric system instability, etc., the VRFs should all be "High". 2. The Time Horizons should all be "Operations Planning" because of the immediacy of a failure to meet the requirements. 3. For the R1 Lower VSL, include a second part to read: Failed to identify calibration tolerances or other equivalent parameters for one Protection System component type that establish acceptable parameters for the conclusion of maintenance activities. For the R1 Moderate VSL, suggest similar wording as for the Lower VSL but specifying two Protection System component types. For the R1 High VSL, suggest changing the wording of the 3rd part to be similar to the Lower VSL to match the requirement and to cater for more than two Protection System component types. 4. For the R3 Severe VSL, in part 3, replace "less" with fewer.
Response: Thank you for your comments. **1. Consideration of the VRFs, in association with the VRF Guidelines, yields the VRFs as established within the draft Standard.** **2. The SDT has reviewed the time horizons, and feels that R1 is 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 had concluded that Requirement R2 is redundant with Requirement R1, Part 1.4, and has deleted R2 (together with the associated Measure and VSL).** **3. The SDT has determined that the fundamental concerns of R1 part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. The associated VSL has also been revised.** **4. The SDT believes that your suggestion is similar to the existing text, and declines to modify the standard.**		

Organization	Yes or No	Question 2 Comment
Platte River Power Authority System Maintenance	No	The 5%, 10%, and 15% levels for R2 & R4 exaggerate the severity levels for small companies. A small DP with only 9 relays in a protection system would only have to be missing 1 record for a severe VSL.
Response: Thank you for your comments. The percentage levels for Requirement R4 are consistent with many other NERC Standards and are also consistent with the guidance within the VSL Guidelines. The SDT concluded that Requirement R2 was redundant with Requirement R1, Part 1.4, and deleted Requirement R2 (together with the associated Measure and VSL).		
Electric Market Policy	No	VSL R3. How do you measure a percentage of countable events over a period of time? How are you to determine what the total population to be considered? An entity should not be penalized if they are following their program, correcting issues, and documenting all actions, even if there is a high failure rate in an instance.
Response: Thank you for your comments. Attachment A, to which Requirement R3 refers, specifies that countable events are assessed on the basis of " for the greater of either the last 30 components maintained or all components maintained in the previous year."		
Bonneville Power Administration	Yes	
Santee Cooper		
NERC Staff		
FirstEnergy	No	The VSL for R2 need to be adjusted since "Condition Based Maintenance" has been removed from the standard.
Response: Thank you for your comments. The SDT concluded that Requirement R2 was redundant with Requirement R1, Part 1.4, and deleted Requirement R2 (together with the associated Measure and VSL).		
Florida Municipal Power Agency	No	The VRF of R1 should be Low since the attached tables are essentially the PSMP.
Response: Thank you for your comments. The SDT disagrees; the Tables establish the intervals and activities, and Requirement R1 addresses the establishment of an entities' individual PSMP.		
PSEG Companies ("Public Service Enterprise Group Companies")		No comment

Organization	Yes or No	Question 2 Comment
MRO's NERC Standards Review Subcommittee	Yes	
Western Area Power Administration	Yes	
TransAlta Centralia Generation Partnership	No	Please provide acronyms list and its explanations in the standard.
Response: Thank you for your comments. In accordance with established NERC custom, acronyms are either established at the first use of the term, or are general acronyms used throughout NERC Standards.		
NextEra Energy	Yes	
City of Austin DBA Austin Energy		
PacifiCorp	Yes	
Southern Company Transmission	No	We disagree with the inclusion of the VSLs, VRFs, and time Horizons associated with the new Requirements 1.5 and 4.2
Response: Thank you for your comments. The SDT determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised.		
Clark Public Utilities	Yes	
Exelon		
Manitoba Hydro	No	The high VSL for R1 “Failed to include all maintenance activities relevant for the identified monitoring attributes specified in Tables 1-1 through 1-5” may be interpreted in different ways and should be further clarified.
Response: Thank you for your comments. The SDT does not understand your concern; further details are needed.		

Organization	Yes or No	Question 2 Comment
Dynegy Inc.	No	For R4, the VRF has been changed to high. We question the need to change to high since there are numerous elements that will still protect the system while repairs are being made.
Response: Thank you for your comments. Requirement R4 addresses implementation of the overall PSMP; that is – maintaining all devices within the program. This VRF is consistent with the "high" assigned to R2 of PRC-005-1.		
Oncor Electric Delivery Company LLC	No	Oncor strongly disagrees with the modification to the Violation Severity Levers (VSL) table under the High VSL column where it states that it is a high VSL for "Failed to establish calibration tolerance or equivalent parameters to determine if components are within acceptable parameters." Oncor feels modifying the standard by adding a requirement that requires a Transmission Owner, Generation Owner or Distribution Provider to "identify calibration tolerances or other equivalent parameters for each Protection System component type that establish acceptable parameters for the conclusion of maintenance activities" is too intrusive and divisive for what it brings to the reliability of the BES. The requirement (Requirement R1 part 1.5) and its associated High VSL should be removed from PRC-005-2.
Response: Thank you for your comments. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised.		
Ingleside Cogeneration LP		
Indiana Municipal Power Agency	No	IMPA does not agree with the percentage in the VSL table for R4. For smaller entities that have six or less of any one type of Protection System Component and they fail, for whatever reason (even if it's a matter of incomplete documentation), to complete scheduled program maintenance on that component they will be subjected to the severe VSL penalty Matrix. Consideration should be given to entities having less than say, 100 of a component. There should be some type of tiered sub table within the VSL matrix for this consideration - registered entities having a certain component in quantities greater than or equal to 100 and registered entities having quantities of that certain component of less than 100.
Response: Thank you for your comments. The percentage levels within Requirement R4 are consistent with many other NERC Standards, and are also consistent with the guidance within the VSL Guidelines. The SDT concluded that Requirement R2 was redundant with Requirement R1, Part 1.4, and deleted Requirement R2 (together with the associated Measure and VSL).		
South Carolina Electric and Gas	Yes	

Organization	Yes or No	Question 2 Comment
Entergy Services	No	R1.5 calls for "identification of calibration tolerances or equivalent parameters..." whereas the associated VSL references "failure to establish calibration criteria...." and is listed as high. If R1.5 is to be included in this standard, then we suggest the severity level of a failure to simply "identify" or document such calibration tolerances would be analogous to the severity level(s) of a "failure to specify one (or the severity level should be consistent with the other elements of R1. Both cases appear to be more of a documentation issue as opposed to a failure to implement. Shouldn't a failure to implement any necessary calibration tolerance be accounted for in R4?
Response: Thank you for your comments. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised.		
Duke Energy	No	1. R1.3 appears to be missing from the VSL for R1. 2. Also, it's unclear to us what the expectation is for compliance documentation for "monitoring attributes and related maintenance activities" in R1.4 and "calibration tolerances or other equivalent parameters" in R1.5. This is fairly straightforward for relays, but not for other component types. 3. R4 - More clarity must be provided on the expectation for compliance documentation. This is a High VRF requirement, and there may only be a small number of maintenance-correctable items, hence a significant exposure to an extreme penalty.
Response: Thank you for your comments. **1. The High VSL for Requirement R1 has been revised in consideration of your comment.** **2. The SDT concluded that Requirement R2 was redundant with Requirement R1, Part 1.4, and deleted R2 (together with the associated Measure and VSL).** **3. Examples of compliance documentation are included within Measure M4 and discussed within Section 15.7 of the Supplementary Reference Document.**		
Wisconsin Electric Power Company		
Independent Electricity System Operator	No	1. R1 Lower - We suggest including a second part as follows: "Failed to identify calibration tolerances or other equivalent parameters for one Protection System component type that establish acceptable parameters for the conclusion of maintenance activities. "

Organization	Yes or No	Question 2 Comment
		2. R1 Moderate - We suggest similar to the Lower VSL but catering for two Protection System component types.R1 High - We suggest changing the wording of the 3rd part to match the requirement and to cater for more than two Protection System component types. 3. Editorial Comment to Severe VSL for R3: In part 3, replace “less” with “fewer”.
Response: Thank you for your comments. **1. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. The associated VSL has also been revised.** **2. The ‘Moderate’ VSL for Requirement R1 appears to be similar to the ‘Lower’ VSL for Requirement R1 as you suggest. The SDT believes that, if more than two Protection System component types are not addressed, the ‘Severe’ VSL is appropriate.** **3. Thank you. The SDT elected not to change the VSL for Requirement R3 as suggested.**		
American Electric Power	No	1. The VSL table should be revised to remove the reference to the Standard Requirement 1.5 in the R1 “High” VSL. 2. All four levels of the VSL for R2 make reference to a “condition-based PSMP.” However, no where in the standard is the term “condition-based” used in reference to defining ones PSMP. The VSL for R2 should be revised to remove reference to a condition-based PSMP; alternatively the Standard could be revised to include the term “condition-based” within the Standard Requirements and Table 1. 3. In multiple instances, Table 1 uses the phrase “No periodic maintenance specified” for the Maximum Maintenance Interval. Is this intended to imply that a component with the designated attributes is not required to have any periodic maintenance? If so, the wording should more clearly state “No periodic maintenance required” or perhaps “Maintain per manufacturers recommendations.” Failure to clearly state the maintenance requirement for these components leaves room for interpretation on whether a Registered Entity has a maintenance and testing program for devices where the Standard has not specified a periodic maintenance interval and the manufacturer states that no maintenance is required.
Response: Thank you for your comments. **1. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. The associated VSL has also been revised.** **2. The SDT concluded that Requirement R2 is redundant with R1, Part 1.4, and deleted Requirement R2 (together with the associated Measure and VSL).** **3. If the indicated monitoring attributes are present, no “hands-on” periodic maintenance is required, as the monitoring of the component is**		

Organization	Yes or No	Question 2 Comment
providing a continuing indication of its functionality.		
ITC	Yes	
ISO New England Inc.	No	1. Because all the requirements deal with protective system maintenance and testing, violations could directly cause or contribute to bulk electric system instability, etc., the VRFs should all be "High". 2. The Time Horizons should all be "Operations Planning" because of the immediacy of a failure to meet the requirements. 3. For the R1 Lower VSL, include a second part to read: Failed to identify calibration tolerances or other equivalent parameters for one Protection System component type that establish acceptable parameters for the conclusion of maintenance activities. 4. For the R1 Moderate VSL, suggest similar wording as for the Lower VSL but specifying two Protection System component types. 5. For the R1 High VSL, suggest changing the wording of the 3rd part to be similar to the Lower VSL to match the requirement and to cater for more than two Protection System component types. 6. For the R3 Severe VSL, in part 3, replace "less" with fewer.
Response: Thank you for your comments. **1. The SDT set the VRFs in accordance with the FERC's and NERC's VRF guidance.** **2. The SDT has reviewed the time horizons, and feels that Requirement R1 is 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 concluded that Requirement R2 was redundant with Requirement R1, Part 1.4, and deleted Requirement R2 (together with the associated Measure and VSL).** **3. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. The associated VSL has also been revised.** **4. The 'Moderate' VSL for Requirement R1 appears to be similar to the 'Lower' VSL for Requirement R1 as you suggest.** **5. The SDT believes that, if more than two Protection System component types are not addressed, the 'Severe' VSL is appropriate.** **6. The SDT believes that your suggestion is similar to the existing text, and declines to modify the standard.**		
Nebraska Public Power District	No	VRF's: 1. The definition of a Medium Risk Requirement included on page 8 of the SAR states: "A requirement that,

Organization	Yes or No	Question 2 Comment
		if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system." The PSMP does not "directly" affect the electrical state or the capability of the bulk electric system. A failure of a Protection System component is required to "directly" affect the BES. Therefore, the PSMP has only an "indirect" affect on the electrical state or the capability of the BES. Requirements R1 through R3 and their subparts are administrative in nature in that they are comprised entirely of documentation. Therefore, I recommend changing the Violation Risk Factor of Requirements R1, R2, and R3 to Lower to be consistent with the Violation Risk Factors defined in the SAR. VSL's: 2. R2: Tables 1-1 through 1-5 refers to time-based maintenance programs. I recommend changing "condition-based" to "time-based" in all four severity levels. 3. SAR Attachment B - Reliability Standard Review Guidelines states that violation severity levels should be based on the following equivalent scores: Lower: More than 95% but less than 100% compliant Moderate: More than 85% but less than or equal to 95% compliant High: More than 70% but less than equal to 85% compliant Severe: 70% or less complaint recommend revising the percentages of the violation severity levels to be consistent with the SAR. 4. R3: The performance-based maintenance program identified in PRC-005 Attachment A provides the requirements to establish the technical justification for the initial use of a performance-based PSMP and the requirements to maintain the technical justification for the ongoing use of a performance-based PSMP. However, it appears the VSLs for Requirement R3 only addresses the ongoing use of the technical justification. a. I recommend revising the VSLs for R3 to include the initial use of the technical justification. Item 2) of R3 Severe VSL is a duplicate of Item 2) of R3 Lower VSL. This item is administrative in nature therefore I recommend deleting Item 2) from R3 Severe VSL. b. The first and third bullets of item 4) of R3 Severe VSL are administrative in nature and should be moved to the Lower VSL c. R4: SAR Attachment B - Reliability Standard Review Guidelines states that violation severity levels should be based on the following equivalent scores: Lower: More than 95% but less than 100% compliant Moderate: More than 85% but less than or equal to 95% compliant High: More than 70% but less than equal to 85% compliant Severe: 70% or less complaint recommend revising the percentages of the violation severity levels to be consistent with the SAR.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. Requirements R1, R2, and R3 are not administrative; they are foundational. Without the fundamental development of a PSMP, an entity is unlikely to actually implement a PSMP that satisfies the reliability needs of the BES. The SDT had concluded that Requirement R2 is redundant with Requirement R1, Part 1.4, and deleted Requirement R2 (together with the associated Measure and VSL).
2. The SDT concluded that Requirement R2 is redundant with Requirement R1, Part 1.4, and deleted Requirement R2 (together with the associated Measure and VSL).
3. The guidelines within the SAR have been superseded by subsequent revisions to the VSL Guidelines. The VSLs in the draft standard adhere to the latest VSL Guidelines and to the June 19, 2008 FERC order on VSLs in Docket No RR08-04-000.
4. Part a – The VSL for Requirement R3 has been modified in consideration of your comments.
Part b – These requirements are not administrative; they are foundational. Without compliance with these requirements, an entity does not have an effective performance-based PSMP, and may be detrimentally affecting reliability.
Part c – The latest VSL Guidelines also provide examples of VSLs similar to those in the draft standard.</td></tr>
<tr><td>CenterPoint Energy</td><td></td><td></td></tr>
<tr><td>American Transmission Company</td><td>Yes</td><td></td></tr>
<tr><td>Consumers Energy</td><td>Yes</td><td></td></tr>
<tr><td>Southern Company Generation</td><td>Yes</td><td></td></tr>
<tr><td>US Bureau of Reclamation</td><td>Yes</td><td>The tables rely on a reference document which is not a part of the standard and as such may be altered without due process. Either the relevant text from the reference needs to be inserted into the standard or the reference itself incorporated into the standard. Specific References such as</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The Tables do not provide a reference to either the Supplementary Reference Document. An entity must comply with the standard when approved. The reference documents provide additional explanation, discussion, and rationale, but are not part of the mandatory standard. Since the reference documents are being developed to accompany the standard, the NERC Standard Development Procedure requires that they be posted with the draft standard and undergo stakeholder review, both initially and with any revision of the standard.</td></tr>
<tr><td>Alliant Energy</td><td>Yes</td><td></td></tr>
</table>

Organization	Yes or No	Question 2 Comment
LCRA Transmission Services Corporation	Yes	
MidAmerican Energy	Yes	
Ameren	No	(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 reliability in that valuable resources will be distracted from other duties.
Response: Thank you for your comments. The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation.		
Xcel Energy	Yes	

3. **The SDT has provided the "Supplementary Reference" document to provide supporting discussion for the Requirements within the standard. Do you have any specific suggestions for improvements?**

Summary Consideration: Some commenters questioned whether the Supplementary Reference Document was a part of the Standard and thus mandatory and enforceable; the SDT responded that this document is not a part of the standard but instead offers guidance/rationale to assist in the implementation of the standard. Various other comments were offered regarding the content of the Supplementary Reference Document, to which the SDT responded accordingly.

Organization	Yes or No	Question 3 Comment
Pepco Holding Inc & Affiliates	Yes	
Pacific Northwest Small Public Power Utility Comment Group	No	
Tennessee Valley Authority	No	
Northeast Power Coordinating Council	No	
Platte River Power Authority System Maintenance	No	
Electric Market Policy	Yes	The document on page 3 states that data available from EPRI (et.al) was utilized by the Standard Drafting Team; however, there are no references to EPRI documents in Section 16. Suggest including EPRI references for completeness.
Response: Thank you for your comments. Page 3 of the Supplementary Reference Document has been revised to remove reference to EPRI documents.		
Bonneville Power Administration		
Santee Cooper	No	

Organization	Yes or No	Question 3 Comment
NERC Staff	Yes	1. In section 2.3, NERC staff recommends noting that the present NERC Glossary definition of Bulk Electric System will be revised in response to FERC Order No. 743. 2. In Section 2.4, NERC staff recommends changing the phrase “relays that use measurements of voltage, current, frequency and/or phase angle” with “protective relays that respond to electrical quantities” for consistency with recent changes to the proposed definition of Protection System.
Response: Thank you for your comments. **1. The SDT believes that it is not advisable to reference future activities, but notes that the standard will be applicable to whatever is defined to be the BES, either today or in the future.** **2. The Supplementary Reference Document has been revised as suggested.**		
FirstEnergy	Yes	The discussions surrounding implementing the PSMP on pages 10 and 11 of the clean copy are troublesome for the following reasons. 1. On Pg. 10, under Sec. 8.1, the 4th bullet item states "If your PSMP (plan) requires more activities then you must perform and document to this higher standard". This statement's use of the word "must" implies that an entity will be audited to their documented maintenance practices, even if those practices exceed the requirements of the PRC-005 standard. The PRC-005 standard, and any standard, details the minimum requirements that must be met to achieve a certain reliability goal. For example, if an entity's program states that it will do maintenance on a relay every 4 years, but the standard only requires maintenance every 6 years, the entity shall be held compliant to the standard's 6 year interval. If the entity in this example decides that in year 4 it must delay its maintenance to year six, that should be allowable since the standard PRC-005-2 requires maintenance every 6 years. 2. Since the standard no longer discusses Condition Based Maintenance, it should be removed from the reference document for consistency.
Response: Thank you for your comments. **1. This text is in the Supplementary Reference Document as a caution to entities that they may be expected to be held accountable for their entire documented PSMP, even if it exceeds the minimum requirements of the standard.** **2. The Supplementary Reference Document discusses condition-based maintenance in a conceptual manner, as a generally-recognized term. The SDT did make some changes within the Supplementary Reference document to clarify the manner in which condition-based maintenance is discussed.**		

Organization	Yes or No	Question 3 Comment
Florida Municipal Power Agency	Yes	
PSEG Companies ("Public Service Enterprise Group Companies")	Yes	Figure 2 "typical generation system" shows a typical auxiliary medium voltage bus, in addition to the color coded elements suggest that a very distinct line of demarcation (dark dotted line) be added to the figure that defines the elements associated with the MV bus protection served by the station Aux Transformer and unit aux transformer are not part of the BES- PSMP PRC5 requirements. Also see comment 5 below; we suggest that the station service transformer must be connected to BES for inclusion in standard requirements. Suggest adding an explanation note to figure 2 to clarify this.
Response: Thank you for your comments. Figure 2 is intended to provide an example to users, not to describe the entire applicability of the draft standard. As such, the SDT does not believe that this figure needs to reflect all possible arrangements, nor does it need to suffice to describe the entire applicability. As for your comment regarding the unit auxiliary transformer, please see the SDT response to your more detailed comments in Question 5.		
MRO's NERC Standards Review Subcommittee	No	
Western Area Power Administration	No	
TransAlta Centralia Generation Partnership	No	
NextEra Energy	No	
City of Austin DBA Austin Energy		
PacifiCorp		
Southern Company Transmission	Yes	1. Page 11 and 12, (Additional Notes for Table 1-1 through 1-5) Comment ->> The standard does not reference these notes. Should these notes be referenced and included in the Standard? 2. Page 12, Additional Notes for Table 1, item #7 ("performing an operational trip test")

Organization	Yes or No	Question 3 Comment
		Comment ->> Standard does not state that an operational/full functional test is required. Please clarify. 3. Page 22, 15.3, Control Circuitry Functions, paragraph 1 ("verify, with a volt-meter, the existence of proper voltage at the open contacts" Comment ->> The example of measuring the proper voltage with a volt-meter at the open contacts to verify the circuit indicates that the 12-year "full functional" trip test of control circuits is not required. Please clarify. 4. Page 22, 15.3, Control Circuitry Functions, paragraph 3 ("UVLS or UFLS scheme are excluded from the tripping requirement, but not from the circuit test requirements") Comment ->> This indicates to me that measuring the proper voltage with a volt-meter at the open contacts will verify the circuit. Please confirm. Please clarify - If a suitable monitoring system is installed that verifies every parallel trip path then the manual-intervention testing of those parallel trip paths can be "extended beyond 12 years". Standard indicates that no periodic maintenance is required. Consider changing "extended beyond 12 years" to "eliminated". 5. Page 23, 15.3, Control Circuitry Functions, paragraph 5 ("When verifying the operation of the 94 and 86 relays each normally-open contact that closes to pass a trip signal must be verified as operating correctly.") Comment ->> This indicates that we must verify that trip and auxiliary device contacts change state. Please confirm. The standard does not state that the contacts must be verified to change states. If this is required, please add to the standard.

Response: Thank you for your comments.

1. **These notes are provided as application guidance relative to the Tables, which as you note, does not reference them.**
2. **This note has been revised within the Supplementary Reference Document in consideration of your comment.**
3. **This example is stated within the Supplementary Reference Document as an example method of testing the dc control circuitry. The draft standard no longer requires a "functional trip test", although it does require that lockout relays and auxiliary relays be operated at least once every 6 years to verify that they function properly.**
4. **The Supplementary Reference Document has been revised as suggested.**
5. **The draft standard specifies "Verify electrical operation" of these components every 6 years. This seems implicitly to require a change of state of the contacts. However, it may be possible to verify electrical operation without having to check the change of state of the individual contacts, but the contacts will have to be checked as part of the 12-year full test. The cited clause/paragraph Supplementary Reference Document has been revised to clarify.**

Organization	Yes or No	Question 3 Comment
Clark Public Utilities	No	
Exelon		
Manitoba Hydro	No	
Dynegy Inc.	No	
Oncor Electric Delivery Company LLC	No	
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration, LP, believes that the Section 15.5 of the Supplementary Reference “Associated communications equipment (Table 1-2)” properly reflects the intent of the validation of relay-to-relay communications. It states that any “evidence of operational test or documentation of measurement of signal level, reflected power or data-error rates can fulfill the requirements.” However, Table 1-2 - which will be the ultimate reference used by audit teams - only clearly allows for the measurement of channel parameters. Although the newer technology relays provide read-outs of signal level or data-error rates that do not require intrusive testing, older relays do not. The tools required to perform such testing are not easily available - and may leave the communications channel in worse shape after testing than it was prior to testing. We believe that Table 1-2 should be updated to clearly state that an operational test is sufficient for the testing of relay-to-relay communication - consistent with the Supplementary Reference.
Response: Thank you for your comments. The standard does not explicitly require measurement of channel parameters, but instead specifies that they may be verified. The Supplementary Reference Document has been revised to remove the discussion of operational testing of the communications channel.		
Indiana Municipal Power Agency	No	
South Carolina Electric and Gas	No	
Entergy Services	Yes	R1.5 calls for “identification of calibration tolerances or equivalent parameters for each Protection System Component Type....”. We believe the Supplementary Reference document should provide additional information and examples of calibration tolerances or equivalent parameters which would be expected for the various component types. Especially for any “equivalent” parameters which would be required for compliance

Organization	Yes or No	Question 3 Comment
		for a component type besides protective relays.
Response: Thank you for your comments. The SDT determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed.		
Duke Energy	No	
Wisconsin Electric Power Company	No	
Independent Electricity System Operator	No	
American Electric Power	Yes	With such a complex standard as this, the FAQ and Supplementary Reference documents do aid the Protection System owner in demystifying the requirements. But AEP holds strong doubt on how much weight the documents carry during audits. It would be better to include them as an appendix in the actual standard, but in a more compact version with the following modifications: 1. Section 5 of the Supplementary Reference, refers to “condition-based” maintenance programs. However, no where in the standard is the term “condition-based” used in reference to defining ones PSMP. The Supplementary Reference should be revised to remove reference to a condition-based PSMP; alternatively the Standard could be revised to include the term “condition-based” within the Standard Requirements and Table 1. 2. Section 15.7, page 26, appears to have a typographical error “...can all be used as the primary action is the maintenance activity...” 3. Figure 2 is difficult to read. The figure is grainy and the colors representing the groups are similar enough that it is hard to distinguish between groups.
Response: Thank you for your comments. The discussion within the Supplementary Reference Document and FAQ are informative, not normative, and thus do not belong as part of the standard. **1. The Supplementary Reference Document discusses condition-based maintenance in a conceptual manner, as a generally-recognized term. The SDT did make some changes within the Supplementary Reference Document to clarify the manner in which condition-based maintenance is discussed.** **2. This clause has been corrected.**		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td colspan="3">3. A higher-quality version of Figure 2 has been substituted.</td></tr>
<tr><td>ITC</td><td>Yes</td><td>1. Auxiliary Relay Testing: We repeat our objection to the 6 year requirement for testing of auxiliary relays. The STD response to our previous objection was:

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. Auxiliary relays are, of course, electromechanical relays, but much less complicated than impedance, differential or even time-overcurrent electromechanical relays. It has been our experience that trip failures are rare and that our present 10 year control, trip tests, and other related testing are sufficient in verifying the integrity of the scheme. Section 8.3 of the Supplementary Reference notes statistical surveys were done to determine the maintenance intervals. Were auxiliary relays included in these surveys in a such a way to verify that they indeed require a 6 year maintenance interval? We recommend they be considered part of the control circuitry, with a 12 year test cycle.

2. High Speed Ground Switch Testing: We repeat our recommendation that the standard state that a high speed ground switch is an interrupting device. We also recommend that testing requirements for High-Speed ground switches be clearly stated in the standard.

Section 15.3 of the Supplementary Reference contains the following: It is necessary, however, to classify a device that actuates a high-speed auto-closing ground switch as an interrupting device if this ground switch is utilized in a Protection System and forces a ground fault to occur that then results in an expected Protection System operation to clear the forced ground fault. 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.

We disagree that a high-speed ground switch can be adequately tested by disconnecting the solenoid triggering unit. The ability of the trip coil to “operate the circuit breaker” must be verified per Table 1-5 Row 1. The ability of the “solenoid triggering unit” to operate the ground switch should be required also. A high-speed ground switch is a unique device. Its maintenance requirements should be specifically included in the standard itself. Based on Draft 3 of the standard, this is a electromechanically operated device and would have to be tested every 6 years. A logical location would be in Table 1-5. Is there test</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>data to support the test method of disconnecting the solenoid triggering unit?</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. The SDT believes that the appropriate interval for electromechanical devices such as aux or lockout relays should remain at 6 years, as these devices contain “moving parts” which must be periodically exercised to remain reliable.
2. PRC-005-2 includes high-speed grounding switch trip coils within the dc control circuitry to the degree that the initiating Protection Systems are characterized as “transmission Protection Systems”. There is currently an unapproved interpretation response (project 2009-17) addressing what is a “transmission protection system.” When this interpretation is approved, the SDT will incorporate it within PRC-005-2. Section 15.3 of the Supplementary Reference Document will be revised to clarify the discussion of testing of the ground-switch trip coil.</td></tr>
<tr><td>ISO New England Inc.</td><td>No</td><td></td></tr>
<tr><td>Nebraska Public Power District</td><td>Yes</td><td>The Supplementary Reference Documents identified are unapproved and in draft form. I believe that only approved documents should be referenced in the Standard. Therefore, I recommend updating the Supplementary Reference Documents section with approved versions of the documents.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The SDT revised the Supplementary Reference Document section of the draft Standard.</td></tr>
<tr><td>CenterPoint Energy</td><td></td><td></td></tr>
<tr><td>American Transmission Company</td><td>No</td><td></td></tr>
<tr><td>Consumers Energy</td><td>No</td><td></td></tr>
<tr><td>Southern Company Generation</td><td>Yes</td><td>1. On Page 4, Paragraph 2.2 is no longer proposed - the paragraphs just before 2.2 need to be revised.
2. On Page 12, item 7, the phrase “operational trip test” is not used in the standard. Please consider using this phrase in the standard.
3. On Pages 14-15, several paragraphs describing the contents of Sections 9, 10, 11, & 13 are given – these appear to be out of place and don’t seem to belong here (just before “9. Performance-Based Maintenance Process).
4. On Page 24, correct the bulleted Protection System Definition to match the most recent definition.</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
		5. On Page 29, please improve the clarity of Figure 2. 6. On Page 31, please revise the flowchart references to R4.4.1 and R4.4.2. 7. Please correct the following formatting: Page 2, Table of Contents; Page 18, the bulleted item list; Page 23, add a space before the last paragraph.
Response: Thank you for your comments. **1. This Section of the Supplementary Reference Document has been corrected.** **2. This Section of the Supplementary Reference Document has been revised.** **3. The Supplementary Reference Document has been revised to address your comment.** **4. The Supplementary Reference Document has been revised to address your comment.** **5. The Supplementary Reference Document has been revised to address your comment.** **6. The Supplementary Reference Document has been revised to address your comment.** **7. The Supplementary Reference Document has been revised to address your comment.**		
US Bureau of Reclamation	Yes	The Supplementary reference provides significant clarity to the intent and application of standard; however, in doing so, it reveals conflicts and ambiguity in the text of the standard. It is suggested that some of the clarifying language be inserted into the text of the standard.
Response: Thank you for your comments. To the extent possible, the clarifying language of the Supplementary Reference Document will be incorporated into the next version of PRC-005 when the standard is drafted in the Results-based format.		
Alliant Energy	No	
LCRA Transmission Services Corporation	Yes	Well written and helpful document. In Section 8.1, the document states that if your PSMP requires activities more often than the Tables maximum, then you must perform to that higher standard. While it is understandable that an entity may desire to maintain their PRS at a higher level, they should not be fined or penalized for achieving less than their standard but within the intervals stated in the Tables. This point should be clarified, preferably within the standard itself.
Response: Thank you for your comments. Requirement R1, Part 1.3 and Requirement R4 within the Standard has been revised in a manner which addresses your comment. However, the SDT re-emphasizes that entities may be expected to be held to their PSMP developed in accordance to		

Organization	Yes or No	Question 3 Comment
Requirement R1, whether it minimally addresses the remainder of the requirements in the standard or exceeds those requirements.		
MidAmerican Energy	Yes	The Supplementary Reference should have clear disclaimers indicating that nothing in the reference is mandatory and enforceable.
Response: Thank you for your comments. NERC establishes that only the Standard is mandatory and enforceable, and Section F of the standard introduces the Supplementary Reference Document as presenting supporting discussion. The introductory area of the Supplementary Reference Document will be revised to clarify this.		
Ameren	No	
Xcel Energy	Yes	1. Requirement R1 of the standard has been changed and no longer states that only relays which sense current, voltage, and phase angle to detect anomalies are in scope. However, it is noted that the new definition of Protection System states "Protective Relays which respond to electrical parameters." Does Section 2.4 of the Supplementary Reference and, in particular, the last sentence of this section, still align with the standard such that sudden pressure devices are not classified as a relay requiring calibration per Table 1-1? Is the tripping path through the Sudden Pressure Device included as DC Control Circuitry per Table 1-5? FAQ II.4.F would indicate testing of trips from 63 devices are also not required. If so, perhaps this should be restated in Section 2.4 of the Supplementary reference. 2. Section 2.4 could be read to imply that "applicable relays" includes IEEE device #86, lockout relays and IEEE device #94, tripping or trip free relays. However, it is apparent from Table 1-1 "Component Type – Protective Relays" that there are no maintenance activities applicable to 86 or 94 devices. On the other hand, Table 1-5 "Component Type - Control Circuitry" does include maintenance activities for electromechanical trip or auxiliary devices. Thus the tables of the standard imply that 86 and 94 devices would be more accurately classified as DC control circuitry rather than relays. We suggest that Section 2.4 be written to clarify the SDT's intent for the component type classification of devices 86 and 94. Note that auditors of PRC-005-1 frequently ask for a list of in scope relays and it would nice to have a definite rationale for excluding 86 and 94 devices from these relay lists.
Response: Thank you for your comments. **1. The Supplementary Reference Document has been revised to clarify this point.** **2. The SDT re-emphasizes that auxiliary and lockout relays are included within the standard as mechanical-operating devices that must be verified to operate within a 6-year interval, and also as devices which must be verified within the verification of all paths of the trip circuits on a 12-year interval. It is left to the entity to determine how to best demonstrate compliance with that requirement to the compliance monitor. The**		

Organization	Yes or No	Question 3 Comment
Supplementary Reference Document has been revised to clarify this point.		

4. The SDT has provided the "Frequently-Asked Questions" (FAQ) document to address anticipated questions relative to the standard. Do you have any specific suggestions for improvements?

Summary Consideration: Commenters suggested corrective language and requested additional discussions within the FAQ document. The SDT decided to eliminate the FAQ document and incorporate its contents into the Supplementary Reference Document as appropriate. The SDT considered all commenters' suggestions during that activity.

Organization	Yes or No	Question 4 Comment
Pepco Holding Inc & Affiliates	Yes	
Pacific Northwest Small Public Power Utility Comment Group	Yes	WECC does not use the definition of the BES that NERC supplied to FERC via http://www.nerc.com/docs/docs/ferc/RM06-16-6-14-07CompFilingPar77ofOrder693FINAL.pdf,so the answer to III.1.3 (page 19-20) is not accurate.
Response: Thank you for your comments. The SDT decided to eliminate the FAQ document and incorporate the FAQ's contents into the Supplementary Reference Document as appropriate. The SDT considered your comments during this activity.		
Tennessee Valley Authority	No	
Northeast Power Coordinating Council	Yes	See response to Question 5 below.
Response: Thank you for your comments. Please see our response to your comments in Question 5.		
Platte River Power Authority System Maintenance	No	
Electric Market Policy	Yes	The FAQ's do not appear to have kept up with the current draft Standard. 1. For example, Question B under Section 2 for Protective Relays, refers to the use of the word "Restoration" in the definition of a Protection System Maintenance Program. The current definition uses the word "Restore." 2. Additionally, Answers B, I, and J under Section 2 for Protective Relays each refer to Requirement R4.3,

Organization	Yes or No	Question 4 Comment
		which in not in the current Standard. Suggest a final edit of the FAQ's to clean-up these type of issues.
Response: Thank you for your comments. The SDT decided to eliminate the FAQ document and incorporate the FAQ's contents into the Supplementary Reference Document as appropriate. The SDT considered your comments during this activity.		
Bonneville Power Administration		
Santee Cooper	No	
NERC Staff	Yes	1. At a minimum, the response to Question II.1.A should be revised to reflect the present revision of Requirement R1. In the current proposed response to the FAQ, the answer refers to text that was deleted from Requirement R1 in the current posting of the standard; i.e., this standard covers protective relays "that use measurements of voltage, current and/or phase angle to determine anomalies and to trip a portion of the BES." The removal of this text from Requirement R1 makes it less clear whether the standard applies to reclosing functions and protective functions used to supervise automatic or manual closing of a circuit breaker to ensure the voltage magnitude and phase angle difference are within specified tolerances. The drafting team also should consider whether additional specificity is required to ensure applicability is clearly defined within the standard. 2. In the response to Question II.2.H, NERC staff notes that the word "than" should be changed to "then" in the phrase "If the component no longer performs Protection System functions than..." 3. In the response to Question II.2.I, NERC staff recommends noting that "When a failure occurs in a protection system, power system security may be compromised, and notification of the failure must be conducted in accordance with relevant NERC standard(s)." The recommended text is included in the Supplementary Reference Document and inclusion in the FAQ response provides consistency and highlights obligations in other standards necessary for BES reliability. 4. In the response to Question III.1.A, NERC staff recommends noting that the present NERC Glossary definition of Bulk Electric System will be revised in response to FERC Order No. 743. 5. In the response to Question III.3.A, NERC staff recommends a more generic reference to NERC UFLS requirements in place of the reference to PRC-007-0, as PRC-007 will be retired pending FERC approval of PRC-006-1.In the response to Question IV.1.A (third paragraph), NERC staff recommends changing the phrase "that are certainly coming to the industry" to "may be coming to the industry" for consistency with the change to the response to Question V.4.A. Both questions appear to address the same or similar concerns.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comments. The SDT decided to eliminate the FAQ document and incorporate the FAQ's contents into the Supplementary Reference Document as appropriate. The SDT considered your comments during this activity.		
FirstEnergy	No	
Florida Municipal Power Agency	Yes	
PSEG Companies ("Public Service Enterprise Group Companies")	Yes	Suggest that the section 5 - station DC supply have some specific examples added that would be acceptable methods for verifying the "state of charge" as required by standard table 1-4.
Response: Thank you for your comments. The SDT decided to eliminate the FAQ document and incorporate the FAQ's contents into the Supplementary Reference Document as appropriate. The SDT considered your comments during this activity. Table 1-4 has been revised to remove "state of charge" from the activities.		
MRO's NERC Standards Review Subcommittee	No	
Western Area Power Administration	No	
TransAlta Centralia Generation Partnership	No	
NextEra Energy	No	
City of Austin DBA Austin Energy		
PacifiCorp		
Southern Company Transmission	Yes	1. Page 7, L. ("verify operation of the relay inputs ...") Comment ->> Clarification needed. Standard states that each input should be "picked up" or "turned on and off". Do you have to change states of the input contact(s) or can you just jumper positive to the input(s) to verify that the microprocessor relay verifies this change of state?

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td></td><td></td><td>2. Page 10, 4.E (“What does functional (or operational) trip test include?”)
Comment ->> The words “functional (or operational) trip test” are not in the Standard. Is this required? If so, please clarify this in Standard. If not, please remove. (Reference comment regarding “verify all paths of the control and trip circuits” on page 17 of standard.)
3. Page 18, 7. (Distributed UVLS and UFLS system.) and Page 19 8. (Centralized UVLS and UFLS system.)
Comment ->> Standard does not specify “distributed” or “centralized” UVLS and UFLS systems. Please consider combining section 7 & 8, omitting items 7.C., 8.E., and omitting “distributed” and “centralized” references on pages 18 and 19.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
The standard does explicitly require that auxiliary relays, lockout, and trip coils of interrupting devices be verified to have electrically operated every 6 years, and this is the only place in the standard that currently requires this sort of activity.
The SDT decided to eliminate the FAQ document and incorporate the FAQ’s contents into the Supplementary Reference Document as appropriate. The SDT considered your comments during this activity.</td></tr>
<tr><td>Clark Public Utilities</td><td>Yes</td><td>Provide answers to the following questions.
Does the completion of a battery ohm test or a battery performance test satisfy the verification requirements for state of charge of the individual battery cells/units, battery continuity, battery terminal connection resistance, and battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)?</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The activities described do not satisfy all of the requirements (at the established intervals) listed in your comment. The SDT decided to eliminate the FAQ document and incorporate the FAQ’s contents into the Supplementary Reference Document as appropriate. The SDT considered your comments during this activity. Table 1-4 has been revised to remove “state of charge” from the activities.</td></tr>
<tr><td>Exelon</td><td>Yes</td><td>1. Clarify what kind of testing is required on lockout relays/86 devices. Specifically, whether functional testing is adequate or if simple calibration, similar to protective relays, is all that is are required.
2. Clarify if protective relays that trip equipment (e.g., a condensate pump that would in turn cause a main generator trip) are also included in the scope of this Standard.
3. Clarify if relays which result in generator run back, but do not trip the generator, are included in the scope of this Standard.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
1. For lockout relays, the standard requires that they be electrically operated every 6 years, and that the trip path be verified every 12 year. No calibration/etc is specified. 2. As described in FAQ III.2.A, protective relays which trip equipment within the plant which may eventually result in tripping of the generator, but do not trip the generator (either directly or via a generator lockout relay) , are not included. 3. If the generator run back scheme is characterized as a Special Protection System within your region, these relays would be included as part of that system (Section 4.2.6- Applicability of the draft Standard). The SDT decided to eliminate the FAQ document and incorporate the FAQ's contents into the Supplementary Reference Document as appropriate. The SDT considered your comments during this activity.		
Manitoba Hydro	Yes	As previously stated, the maintenance requirements for batteries listed in Table 1-4 do not appear to be consistent with example 1 in Section V, 1A of the FAQ. Specifically the FAQ does not mention the of the individual battery cells/units, the battery continuity, the battery terminal connection resistance, the battery internal cell-to-cell or unit-to-unit connection resistance, or the cell condition which are indicated as 18 month interval tasks in table 1-4.
Response: Thank you for your comments. The SDT decided to eliminate the FAQ document and incorporate the FAQ's contents into the Supplementary Reference Document as appropriate. The SDT considered your comments during this activity. Table 1-4 has been revised to remove "state of charge" from the activities.		
Dynegy Inc.	No	
Oncor Electric Delivery Company LLC	Yes	There is still confusion in Table 1-4 concerning the "Monitored Station dc supply." The uncertainty is over whither an Owner must have all seven (7) monitoring activities (Station dc supply voltage, State of charge of the individual battery cell/units, Battery continuity of station battery, Cell-to-cell and battery terminal resistance, Electrolyte level of all cells in station battery, Unintentional dc grounds, and Cell/unit internal ohmic values of station battery) listed in the table or just one of them to take advantage of forgoing the maximum maintenance interval for an activity and going to the 6 year maximum maintenance interval to verify that the monitoring device is calibrated. A FAQ concerning this question would be beneficial to those who are concerned that they must monitor all seven activities in order to take advantage of condition based maintenance for the station dc supply. Also an explanation of how each of the 7 monitoring activities relates to a specific station dc supply maintenance activity might be beneficial.
Response: Thank you for your comments. Table 1-4 has been further revised to address your concern (see Table 1-4(f)). The SDT decided to eliminate the FAQ document and incorporate the FAQ's contents into the Supplementary Reference Document as appropriate. The SDT considered your comments during this activity. Table 1-4 has been revised to remove "state of charge" from the activities.		

Organization	Yes or No	Question 4 Comment
Ingleside Cogeneration LP		
Indiana Municipal Power Agency	No	
South Carolina Electric and Gas	No	
Entergy Services	Yes	Section II.2.B references R4.3 which has been revised to R4.2.
Response: Thank you for your comments. The SDT decided to eliminate the FAQ document and incorporate the FAQ's contents into the Supplementary Reference Document as appropriate. The SDT considered your comments during this activity.		
Duke Energy	Yes	There are typographical errors on the FAQ Requirements Flowchart (should be R4.1.1 and R4.1.2 instead of R4.4.1 and R4.4.2).
Response: Thank you for your comments. The SDT decided to eliminate the FAQ document and incorporate the FAQ's contents into the Supplementary Reference Document as appropriate. The SDT considered your comments during this activity.		
Wisconsin Electric Power Company	Yes	Table 1-4 requires an activity to verify the state of charge of battery cells. There are no possible options for meeting this requirement listed in the FAQ document. Unlike other terms used in the standard, this term is not mentioned or defined in the FAQ. To comply with this standard, the SDT needs to provide more guidance. For example, for VLA batteries the measured specific gravity could indicate state of charge. For VRLA batteries, it is not as clear how to determine state of charge, but possibly this can be determined by monitoring the float current.
Response: Thank you for your comments. The SDT decided to eliminate the FAQ document and incorporate the FAQ's contents into the Supplementary Reference Document as appropriate. The SDT considered your comments during this activity. Table 1-4 has been revised to remove "state of charge" from the activities.		
Independent Electricity System Operator	No	
American Electric Power	Yes	With such a complex standard as this, the FAQ and Supplementary Reference documents do aid the Protection System owner in demystifying the requirements. But AEP holds strong doubt on how much weight the documents carry during audits. It would be better to include them as an appendix in the actual standard, but in a more compact version with the following modifications:

Organization	Yes or No	Question 4 Comment
		1. The section "Terms Used in PRC-005-2" is blank and should be removed as it adds no value. 2. Section I.1 and Section IV.3.G reference "condition-based" maintenance programs. However, no where in the standard is the term "condition-based" used in reference to defining ones PSMP. The FAQ should be revised to remove reference to a condition-based PSMP; alternatively the Standard could be revised to include the term "condition-based" within the Standard Requirements and Table 1. 3. The second sentence to the response in Section I.1 appears to have a typographical error "... an entity needs to and perform ONLY time-based...".
Response: Thank you for your comments. The discussion within the Supplementary Reference and FAQ are informative, not normative, and thus do not belong as part of the standard. The SDT decided to eliminate the FAQ document and incorporate the FAQ's contents into the Supplementary Reference Document as appropriate. The SDT considered your comments during this activity.		
ITC	No	
ISO New England Inc.	Yes	See response to Question 5 below.
Response: Thank you for your comments. Please see our response to your comments in Question 5.		
Nebraska Public Power District	No	
CenterPoint Energy	Yes	The need for an FAQ document, in addition to an extensive Supplementary Reference document, illustrates the complexity and impracticality of the proposed Standard. CenterPoint Energy does not support the development of an additional type of document, that is, the FAQ document. CenterPoint Energy recommends eliminating the FAQ document and using only a Supplementary Reference" document. This would also provide the benefit of not having contradictory information in the two documents.
Response: Thank you for your comments. The SDT believes that entities should be able to implement the standard without either the FAQ or Supplementary Reference. However, the SDT is also convinced that many entities may find the supporting discussion/rationale useful, particularly to assist them in implementing the standard in an efficient manner. The SDT decided to eliminate the FAQ document and incorporate the FAQ's contents into the Supplementary Reference Document as appropriate.		
American Transmission Company	Yes	1. FAQ Protective Relays 2.D: The last sentence is not consistent with the discussions at the "March 2010, Standard Drafting Team Meeting, Project 2007-17". The understanding from that meeting was that the relay settings would be verified that the "as left" settings were the same as the "as found" settings and that the intent was not to verify the settings against a Master Record. Therefore the intent is that the tester will

Organization	Yes or No	Question 4 Comment
		verify that no setting changes were made as part of the testing process. Please include this clarification with the language in the standard. 2. FAQ Group by Type of Maintenance Program 2.B: We agree with the use of either the in-service date or the commissioning date to start the initial due date calculation for maintenance. Please include this clarification with the language in the standard.
Response: **1. The intent is that the settings of the component be as specified at the conclusion of maintenance activities, whether those settings may have "drifted" since the prior maintenance or whether changes were made as part of the testing process.** **2. The discussion within the Supplementary Reference and FAQ are informative, not normative, and thus do not belong as part of the standard. The SDT decided to eliminate the FAQ document and incorporate the FAQ's contents into the Supplementary Reference Document as appropriate. The SDT considered your comments during this activity.**		
Consumers Energy	No	
Southern Company Generation	Yes	1. On Page 3, please revise the flow chart references to R4.4.1 and R4.4.2. Also, add (Attachment A) to the "Performance Based" label. 2. On Page 7, Section I, correct the reference of R4.3 to R4.2. 3. Also, revise the last paragraph in Section I to the following: The entity should assure that the component performance is acceptable at the conclusion of the maintenance activities or initiate resolution of any indentified maintenance correctable issues. 4. On Page 7, Section J, correct the reference of R4.3 to R4.2. 5. On Page 10, Section D, a reference is made to "trip test" Table 1. Should this be Table 1-5? The exact phrase "trip test" is not used in the standard. Should it be? 6. On Page 10, Section e, the phrase "functional (or operational) trip test" is not used in the standard – should it be? 7. On Page 11, Section 5A, correct the reference of Table 1 to Table 1-4 in the Station Battery and Emerging Technologies paragraph. 8. On Page 12, Section B, correct the reference of Table 1 to Table 1-4. (2X)

Organization	Yes or No	Question 4 Comment
		9. On Page 13, Section F, correct the reference of Table 1 to Table 1-4. (1X) 10. On Page 14, Section G, correct the reference of Table 1 to Table 1-4. (3X) 11. On Page 14, Section G, change the text “The first maintenance activity” to The capacity testing activity”. 12. On Page 14, Section G, change the text “The second maintenance activity”, to The internal ohmic measurement activity”. 13. On Page 14, Section H, correct the reference of Table 1 to Table 1-4. (1X) 14. On Page 17, Section C, correct the reference of Table 1 to Table 1-5. (1X) 15. Please address what is meant by “Battery terminal connection resistance” on Page 14, Table 1-4 of the standard.
Response: Thank you for your comments. The discussion within the Supplementary Reference and FAQ are informative, not normative, and thus do not belong as part of the standard. The SDT decided to eliminate the FAQ document and incorporate the FAQ’s contents into the Supplementary Reference Document as appropriate. The SDT considered your comments during this activity.		
US Bureau of Reclamation		No Comment
Alliant Energy	No	
LCRA Transmission Services Corporation	Yes	
MidAmerican Energy	Yes	The Frequently Asked Questions should have clear disclaimers indicating that nothing in the reference is mandatory and enforceable.
Response: Thank you for your comments. NERC establishes that only the Standard is mandatory and enforceable, and Section F of the standard introduces this (and the Supplementary Reference Document) as presenting supporting discussion. The SDT decided to eliminate the FAQ document and incorporate the FAQ’s contents into the Supplementary Reference Document as appropriate. The introductory area of the Supplementary Reference Document will be revised to address your concern.		
Ameren	No	This document is helpful.
Xcel Energy	Yes	The changes in the standard and edit attempts on the FAQ have created some problems and confusion. Examples; The new FAQ I.1 answer does not make sense “An entity needs to and perform ONLY time-based

Organization	Yes or No	Question 4 Comment
		. . .” FAQ II.1.A: Requirement R1 no longer contains the statement that “use voltage, current, or phase angle to detect anomalies” so the answer to this FAQ is now out of synch with the standard. FAQ II.2.B – “Restoration” is no longer in the PMSP and has been changed to “Restore” and R4.3 no longer exists. FAQ II.2.I and II.2.J answers also references non-existent requirement R4.3. These are just some examples of fidelity issues that have been created by the most recent edit of PRC-005-2 – we did not perform a review of the entire document. The SDT should be commended for its efforts on the FAQ document as it is exceedingly helpful and well written. However, it needs to be brought back into alignment with the Standard. It is apparent that this fidelity check between the standard and the FAQ was not done prior to this posting. Finally, it seems some FAQs would be warranted to help explain the intent of new requirements R1.5 and R4.2 especially in regards to non-quantifiable maintenance results such as battery visual inspection as well as to provide examples of “other equivalent parameters” acceptance criteria for the various component types included in the Protection System definition
Response: Thank you for your comments. The SDT decided to eliminate the FAQ document and incorporate the FAQ’s contents into the Supplementary Reference Document as appropriate. The SDT considered your comments during this activity.		

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

Summary Consideration: Many commenters disagreed with Requirement R1, Part 1.5 which was added in the previous draft; in response, the SDT removed Requirement R1, Part 1.5 from the standard. Commenters also observed that Requirement R1, Part 1.4 was redundant with Requirement R2, and the SDT removed R2 in response to these comments. Many commenters objected to 4.2.5.5 in the Applicability Section; the SDT removed this clause.

Organization	Yes or No	Question 5 Comment
Pepco Holding Inc & Affiliates	Yes	1. What "specific statistical data" was used to validate that unmonitored communication systems are 24 times more prone to failure than unmonitored protective relays? Comments were previously submitted 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." The 3 month interval is very burdensome and our experience does not appear to justify. A longer interval should be reconsidered.
Response: Thank you for your comments. The SDT reasserts that 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. If an entity's experience is that these components require less-frequent maintenance, a performance-based program in accordance with R3 and Attachment A is an option.		
Pacific Northwest Small Public Power Utility Comment Group	No	
Tennessee Valley Authority	Yes	1R4 - "Identification of the resolution" and "Initiation of the resolution" are very distinct activities. In other places in this standard the requirement is for the resolution to be initiated, that is identified in a corrective maintenance work order, "identification of a resolution" requires technical expertise and can be difficult to track and might change over time for a particular problem. Proposed Change: Change "identification" to "initiation" in phrase "including identification of the resolution...". Overall: NERC is making significant changes to this sizeable standard and only allowing minimum comment period. While this is a good standard that has clearly taken many hours to develop, we are primarily voting

Organization	Yes or No	Question 5 Comment
		"NO" because of the hurried fashion it is being commented, voted, and reviewed.
Response: Thank you for your comments. Requirement R4 has been revised.		
Northeast Power Coordinating Council	Yes	1. In general, the standard is overly prescriptive and complex. It should not be necessary for a standard at this level to be as detailed and complex as this standard is. Entities working with manufacturers, and knowledge gained from experience can develop adequate maintenance and testing programs. 2. Why are "Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, pressure, seismic, thermal or gas accumulation)..." not included? The output contacts from these devices are oftentimes connected in tripping or control circuits to isolate problem equipment. 3. Due to the critical nature of the trip coil, it must be maintained more frequently if it is not monitored. Trip coils are also considered in the standard as being part of the control circuitry. Table 1-5 has a row labeled "Unmonitored Control circuitry associated with protective functions", which would include trip coils, has a "Maximum Maintenance Interval" of "12 Calendar Years". Any control circuit could fail at any time, but an unmonitored control circuit could fail, and remain undetected for years with the times specified in the Table (it might only be 6 years if I understand that as being the trip test interval specified in the table). Regardless, if a breaker is unable to trip because of control circuit failure, then the system must be operated in real time assuming that that breaker will not trip for a fault or an event, and backup facilities would be called upon to operate. Thus, for a line fault with a "stuck" breaker (a breaker unable to trip), instead of one line tripping, you might have many more lines deloaded or tripped because of a bus having to be cleared because of a breaker failure initiation. The bulk electric system would have to be operated to handle this contingency. 4. In reference to the FAQ document, Section 5 on Station dc Supply, Question K, clarification is needed with respect to dc supplies for communication within the substation. For example, if the communication systems were run off a separate battery in separate area in a substation, would the standard apply to these batteries or not? 5. To define terms only as they are used in PRC-005-2 is inviting confusion. Although they may be unique to PRC-005-2, some or all of them may be used in future standards, some already may be used in existing standards, and may or may not be deliberately defined. Consistency must be maintained, not only for administrative purposes, but for effective technical communications as well. 6. What is the definition of "Maintenance" as used in the table column "Maximum Maintenance Interval"? Maintenance can range from cleaning a relay cover to a full calibration of a relay. 7. A control circuit is not a component, it is made up of components.

Organization	Yes or No	Question 5 Comment
		8. Sub-requirement 1.5 needs to be clarified. It is not clear what "Identify calibration tolerances or other equivalent parameters..." means, and may be subject to different interpretations by entities and compliance enforcement personnel. 9. In the Implementation plan for Requirement R1, recommend changing "six" to fifteen. This change would restore the 3-month time difference that existed in the previous draft, between the durations of the implementation periods for jurisdictions that do and do not require regulatory approval. It will ensure equity for those entities located in jurisdictions that do not require regulatory approval, as is the case in Ontario. 10. The 'box' for "Monitored Station dc supply..." in Table 1-4 is not clear. It seems to continue to the next page to a new box. There are multiple activities without clear delineation. 11. Regarding station service transformers, Item 4.2.5.5 under Applicability should be deleted. The purpose of this standard is to protect the BES by clearing generator, generator bus faults (or other electrical anomalies associated with the generator) from the BES. Having this standard apply to generator station service transformers, that have no direct connection to the BES, does meet this criteria. The FAQs (III.2.A) discuss how the loss of a station service transformer could cause the loss of a generating unit, but this is not the purpose of PRC-005. Using this logic than any system or device in the power plant that could cause a loss of generation should also be included. This is beyond the scope of the NERC standards. 12. The Drafting Team must respond to the following concerns raised in the FERC NOPR, Docket No. RM10-5-000, Interpretation of Protection System Reliability Standard, December 16, 2010) to "prevent a gap in reliability". a. Any component that detects any quantity needed to take an action, or that initiates any control action (initial tripping, reclosing, lockout, etc.) affecting the reliability of the Bulk-Power System should be included as a component of a Protection System, as well as any component or device that is designed to detect defective lines or apparatuses or other power system conditions of an abnormal or dangerous nature and to initiate appropriate control circuit actions. b. The exclusion of auxiliary relays will result in a gap in the maintenance and testing of Protection Systems affecting the reliability of the Bulk-Power System. c. Excluding the maintenance and testing of reclosing relays will result in a gap in the maintenance and testing of relays affecting the reliability of the Bulk-Power System. d. Not establishing the specific requirements relative to the scope and/or methods for a maintenance and testing program for the DC control circuitry that is necessary to ensure proper

Organization	Yes or No	Question 5 Comment
		operation of the Protection System, including voltage and continuity.

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. Further, FERC Order 693 directs NERC to establish maximum allowable intervals, which implies that minimum activities also need be prescribed. If an entity's experience is that components require less-frequent maintenance, a performance-based program in accordance with Requirement R3 and Attachment A is an option.**
2. **The SDT concentrated their efforts on protective relays which use the entire group of component types within the Protection System definition. Also, there is currently no technical basis for the maintenance of the devices which respond to non-electrical quantities on which to base mandatory standards related either to activities or intervals. Absent such a technical basis, we are currently unable to establish mandatory requirements, but may do so in the future if such a technical basis becomes available.**
3. **According to Table 1-5, trip coils of interrupting devices must be verified to operate every 6 years, rather than the 12-year interval. As a regional entity, you can specify Supplementary regional requirements to maintain these devices more frequently if you desire.**
4. **With respect to dc supply associated only with communications systems, we prescribe, within Table 1-2, that the communications system must be verified as functional every 3 months, unless the functionality is verified by monitoring. The specific station dc supply requirements (Table 1-4) do not apply to the dc supply associated only with communications systems. The SDT has decided to eliminate the FAQ and incorporate topics and discussion from the FAQ within the Supplementary Reference Document. Your comments will be considered within that activity.**
5. **The SDT has proposed these terms for use only within PRC-005-2 because we are concerned that other uses of these terms, either now or in the future, may not be consistent with the terms as used here. They are defined only for clarify within this standard. The SDT will confirm with NERC staff that this approach is acceptable.**
6. **As used in the "Maximum Maintenance Interval" column title of the table, maintenance refers to whatever activities are specified in the Activities column. The term is capitalized in the column title in conformance with normal editorial practice as a title, rather than as a definition**
7. **For purposes of this standard, the control circuit IS defined as one component type.**
8. **The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary. Therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.**
9. **In consideration of your comment, "six" has been modified to "twelve" in the Implementation Plan for Requirement R1, making it consistent with the remainder of the Implementation Plan.**
10. **Table 1-4 has been further modified for clarity**
11. **In response to many comments, including yours, the SDT has removed 4.2.5.5 from the Applicability of the standard.**

Organization	Yes or No	Question 5 Comment
12. The FERC NOPR is a notice-of-proposed-rulemaking and is not yet a directive. At such a time as a directive is published, NERC will take the necessary actions to address it.		
Platte River Power Authority System Maintenance	Yes	1. Please clarify what is required by R1.5: Identify calibration tolerances or other equivalent parameters for each Protection System component type that establish acceptable parameters for the conclusion of maintenance activities required. Is the intent a brief summary for each component type in the PSMP that would cover all equipment within that component type, or is it a detailed list of each piece of equipment within each component type? 2. The inclusion of dated check-off lists in M4 provides much needed clarity to the list of evidence.
Response: Thank you for your comments. **1. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.** **2. Thank you for your support.**		
Electric Market Policy	Yes	1. The draft to PRC-005-2 contains defined terms that upon approval will remain with the standard rather than being moved to the Glossary of Terms. These terms when used in the Requirements are not designated in any way (e.g., capitalization, bold, etc.) to point the reader back to the in-standard definition. 2. Need to explicitly state the intent of the SDT to either (1) use the newly defined term “Protection System (modification)” only in this standard (PRC-005-2) or (2) replace the existing definition of the existing term in the “Glossary of Terms Used in NERC Reliability Standards” with the proposed definition for the existing term. 3. The language used in Footnote 1 on Attachment A does not agree with the definition of Countable events provided elsewhere in the draft standard. Suggest footnote be removed. 4. Requirement R1.5 uses the phrase “or other equivalent parameters” which is confusing. Suggest replacing with “or acceptance criteria.” Requirement R1.5 should read as follows: “Identify calibration program.” The currently proposed language focuses on specific calibration tolerances and acceptance parameters. These tolerances are developed on a per device, per location basis and would be captured at a procedural level, not a program level. To add this at a program level would only complicate the program and would not lend any improvement to the reliability of the bulk electric system. We recommend maintaining a general calibration requirement, similar to what is stated above, for an entity to develop their calibration program. 5. Requirement 2 Component should be replaced with Component Type. Creating a program to monitor the

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>equipment at this level of equipment would not add any value to the bulk electric system as all components should already be included in component type maintenance tasks. Recommend removing the definition of Component.

6. The requirement to address “monitoring attributes” in Requirement 2 for time based maintenance program is unclear, onerous and unnecessary for a reliable protection system program.

7. Requirement (R4) should identify correctible maintenance issues not the resolution of these issues. The language in R4.2 should strike correcting maintenance issues related to R1.5 and instead state: Any maintenance correctible issues found during the maintenance activity should be identified”

8. Table 1.2 change time frame from 3 months to 3 years.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.

1. The standard capitalizes defined terms only when they refer to terms which are (or will be) in the NERC Glossary of Terms. Terms will generically be capitalized when appearing at the beginning of a sentence or within a title, in accordance with common editorial practice.

2. The statement of the definition has been revised in the standard as “NERC Board of Trustees Approved Definition”, but will remain in the posted draft standard until it is successfully balloted for the convenience of stakeholders.

3. The footnote has been removed.

4. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.

5. The SDT disagrees; monitoring attributes must be present on the individual components as actually installed, not to the overall component type.

6. The SDT believes that the verifiable presence of the monitoring attributes on the individual components as installed is a necessary element of using the extended maintenance intervals that result from the monitoring. If you consistently use specific monitoring attributes on all components within a group, they may be able to address these attributes on a global basis. If an entity does not wish to document these attributes, they are free to apply the maintenance intervals and activities specified for the unmonitored components.

7. Requirement R4 has been revised. The SDT believes it important that the entity initiate resolution of maintenance correctable issues, in addition to simply identifying them.

8. The SDT believes that the 3-month interval is proper for verification of the functionality of unmonitored communications systems.</td></tr>
<tr><td>Bonneville Power Administration</td><td>Yes</td><td>Some of the maintenance tasks need to be defined:

1. The state of charge of each individual cell may need to be better defined. There are means to verify the</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
		state of charge of the entire bank, but not each individual cell. 2. Battery continuity needs to be defined.- There is no mention to what the limits are for the "other equivalent parameters" when performing maintenance activities, just that they need to be identified. There are a large number of battery models which creates a large contrast of parameters, which cannot be grouped together. It is also difficult to get baseline values for older battery models which could result in moving baselines until they become more accurate as the database is populated. 3. If corrective actions are required, is there a maximum allowable duration for when they need to be resolved? 4. The maximum allowable maintenance for station batteries (impedance testing and performance/service testing) is too frequent and suggest an extension or alternative testing methods to stay in compliance. 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 monthly.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. 5. BPA also does not perform routine capacity testing, this is an as required maintenance task to confirm/validate our other test results if needed. BPA would like to see clarification for these issues before we can fully support this standard.
Response: Thank you for your comments. **1. Table 1-4 has been revised to remove "state of charge" from the activities.** **2. This is thoroughly discussed in Section 15.4 of the Supplementary Reference Document.** **3. No. The SDT appreciates that some corrective actions for maintenance correctable issues may take an extended period of time to complete, and has therefore not included completion of the corrective actions within PRC-005-2.** **4. The SDT believes that the 18-month interval is proper for these activities.** **5. For vented lead-acid and valve-regulated lead batteries, alternative activities are specified if desired instead of capacity tests. If Ni-Cad batteries are used, capacity tests are required.**		
Santee Cooper	No	We do not agree with the addition of Requirements 1.5 and 4.2 without work on or review by the Power System Maintenance and Testing Drafting Team. While some maintenance activities on some component types (such as calibration testing of electromechanical relays) translate inherently well into these requirements, the requirements of tolerances and documentation do not fit as well to all maintenance activities on other types of equipment considered part of the protective system. These requirements need to

Organization	Yes or No	Question 5 Comment
		be worked on through the drafting team to make them viable and effective for all protective system component types.
Response: Thank you for your comments. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.		
NERC Staff	Yes	1. Commissioning (Initial) Testing: During development of PRC-005-2, NERC staff has observed a trend in system disturbances involving Protection System problems that should have been identified and corrected during commissioning (initial) testing. While NERC staff recognizes that the addition of commissioning testing may be unrealistic at this stage in the standard drafting process, we want to emphasize its importance. If the SDT chooses to leave commissioning testing out at this juncture, we plan to pursue other avenues to ensure its eventual inclusion through a separate standards project. NERC staff agrees with the SDT's opinion that without commissioning testing, a registered entity responsible for compliance with this standard cannot provide proof of its interval testing period as required by the standard. As soon as the entity puts the protective scheme into service, time "0" for interval testing begins. The next testing interval would be some specific number of years in the future from time "0. "An entity's failure to properly commission new protection system equipment has caused or exacerbated several recent events, greatly impacting BPS reliability. The following are examples of errors that were not detected during commissioning. These undetected errors were observed by NERC staff during event analysis and investigation activities: oFailure to apply correct relay settings. This has occurred repeatedly and has been due to improper procedures, poor document control, misapplication or miscalibration of the relay, or a combination of the above. oFailure to install the proper CT or PT ratio occurred due to poor document control practices and resulted in an undesired protection system response after the equipment was placed in service. oFailure to conduct a functional test of new control circuits to the schematic diagram resulted in an undesired protection system response after equipment was placed in service. oAn incorrect CT ratio was not detected during commissioning, and the equipment was subsequently placed in service. Because in-service testing was not performed, the error remained undetected until the relay misoperated during a fault. Many of the above conditions can remain undetected for extended periods, until they are revealed by a

Organization	Yes or No	Question 5 Comment
		relay misoperation during fault or heavy load conditions. The affects resulting from these cases could have been prevented with proper commissioning testing. We believe that by requiring commissioning testing for new protection system equipment, the reliability of BPS would be improved. 2. Requirement 2:In Requirement 2, it is unclear what is meant by “shall verify those components possess the monitoring attributes identified in Tables 1-1 through 1-5 in its PSMP” because the use of terms in the Requirement is not consistent with the column headings used in Tables 1-1 through 1-5. It also is not clear that components need not possess all attributes; rather, they must possess all attributes consistent with the Maximum Maintenance Interval specified in an entity’s PSMP. NERC staff recommends revising R2 to provide additional clarity as follows:”Each Transmission Owner, Generator Owner, and Distribution Provider that uses maintenance intervals for monitored Protection Systems described in Tables 1-1 through 1-5, shall verify those components possess the monitoring attributes Component Attributes identified in the first column of Tables 1-1 through 1-5 consistent with the Maximum Maintenance Interval specified in its PSMP.”
Response: Thank you for your comments. **1. Thank you for your comments.** **2. Requirement R2 of the standard has been modified as you suggested.**		
FirstEnergy	Yes	REQUIREMENTS 1. Requirement R1 - Subpart 1.5 - We do not support this subpart for the following reasons and offer the following suggestions: To satisfy R1.5, a calibration tolerance or other equivalent parameter would have to be established for each item included in the definition. Many devices which may have similar functionality may also have different performance criteria that would preclude the use of a "one size fits all" calibration tolerance. Many of these criteria are provided by the manufacturer and often vary by manufacturer for a similar device. It would be very difficult to specify in your program all of the calibration tolerances or other equivalent parameters associated with the protection system components. Therefore, we suggest the team delete Subpart 1.5 of Req. R1, and revise Subpart 4.2 of Req. R4 to read: "Initiate resolution of any identified maintenance correctable issues at the conclusion of maintenance activities for Protection System components." IMPLEMENTATION PLAN 2. On pg. 2 of the implementation plan, under "Retirement of Existing Standards", the statement "The existing standards PRC-005-1, PRC-008-0, PRC-011-0, and PRC-017-0 shall be retired upon regulatory approval of PRC-005-2" is not accurate. Since the new PRC-005-2 standard allows for at least 12 months

Organization	Yes or No	Question 5 Comment
		to become compliant with Requirement R1 - establish a Protection System Maintenance Program (PSMP) -the existing standards are still effective during this time. Additionally, we have concerns with the "General Considerations" describing protocols for compliance audits conducted during the allowed 12 month development period of the PSMP and that entities could specify for "each component type" whether maintenance of that component is being performed according to its maintenance program under the "retired" PRC maintenance standards or the new PRC-005-2 standard. In our view, this creates a level of compliance complexity for both the Registered Entity and Regional Entity that should be avoided in the transition to PRC-005-2. FirstEnergy proposes that the Implementation Plan state that the existing standards remain in effect for one year past applicable approval (NERC Board or Regulatory) and that they are retired coincident with the one-year transition to Requirement R1 of PRC-005-2 which would establish all Registered Entities having a new PSMP per the expectations of PRC-005-2. At that time all entities would be required to be under the new PRC-005-2 standard and begin implementing their PSMP per the phased-in Implementation Plan for the remaining requirements. To summarize, per our above discussion we propose the team perform the following:1. Revise the Implementation Plan section titled "Retirement of Existing Standards" section to read as follows: "The existing Standards PRC-005-1, PRC-008-0, PRC-011-0 and PRC-017-0 shall be retired on the first day of the first calendar quarter twelve months following applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter 12 months following the Board of Trustees adoption"2. Remove the entire "General Considerations" section from the Implementation Plan. 3. The bulleted item under the section titled "Implementation plan for R1" has a discrepancy in the time allowed to implement R1 between entities applicable to regulatory approval of the standard versus those in jurisdictions where no regulatory approval is needed and base their adherence per the Board of Trustee adoption. Please revise to reflect a 12 month transition period for each. DEFINITIONS 4. Maintenance Correctable Issue - This is a maintenance standard and this concept gets into the long term repair activities. Is this really appropriate in this standard? If NERC feels repairing is critical to BES reliability, then they should probably initiate a standard in that area. 5. Component - Regarding the phrase "local zone of protection", why is this in quotes? Is there a narrow definition for this? If so, this term should be defined also. DATA RETENTION SECTION 6. 1.3 Regarding the data retention for Req. R3 and R4, it is not practical to keep potentially 24 years of data for components that are maintained every 12 years. We suggest rewording this to "For R3 and R4, Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performances of each distinct maintenance activity for the Protection System components, or to the

Organization	Yes or No	Question 5 Comment
		previous scheduled audit date, whichever is longer". 7. ATTACHMENT A - FOOTNOTE 1This footnote regarding countable events needs to be revised to match the definition of countable events found at the beginning of the standard.
Response: Thank you for your comments. **1. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.** **2. The SDT had concluded that Requirement R2 is redundant with Requirement R1, Part 1.4, and has deleted Requirement R2 (together with the associated Measure and VSL).** **3. The Implementation Plan for Requirement R1 has been modified as you suggest.** **4. The SDT believes that the activities necessary to restore a Protection System component to proper service is an essential part of the PSMP. Please note that the related requirements only address initiation of the corrective actions, not completion, in deference to the extended period of time that some of these activities may take.** **5. The quotes have been removed from the definition of component. However, the SDT believes that this term is a commonly-understood term within the industry.** **6. 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 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. This seems to be consistent with the current practices of several Regional Entities.** **7. This footnote has been removed.**		
Florida Municipal Power Agency	Yes	1. UFLS and UVLS maintenance and testing is greatly expanded, e.g., we interpreted PRC-008/011 as being only the UFLS/UVLS equipment. The new PRC-005 sweeps in other protection system components, e.g., communications (probably not applicable), voltage and current sensing devices (e.g., instrument transformers), Station DC supply, control circuitry. What's key about this is that these components are all part of distribution system protection, so, these activities would not be covered by other BES protection system maintenance and testing. I'm sure we are testing batteries and the like, but, we are probably not testing battery chargers and control circuitry, and, in many cases distribution circuits are such that it is very difficult, if not impossible, to test control circuitry to the trip coil of the breaker without causing an outage of the customers on that distribution circuit. There is no real reliability need for this either. Unlike Transmission and Generation Protection Systems which are needed to clear a fault and

Organization	Yes or No	Question 5 Comment
		may only have one or two back-up systems, there are thousands and thousands of UFLS relays and if one fails to operate, it will not be noticeable to the event. It does make sense to test the relays themselves in part to ensure that the regio0nsl UFLS program is being met, but, to test the other protection system components is not worthwhile. Note that DC Supplies and most of the control circuitry of distribution lines are "tested" frequently by distribution circuits clearing faults such as animals, vegetation blow-ins, lightning, etc., on distribution circuits, reducing the value of testing to just about null. However, this version is better than prior versions because it essentially requires the entity to determine it's own period of maintenance and testing for UFLS/UVLS for DC Supply and control circuitry. 2. Applicability, 4.2.1, should reflect the Y&W and Tri-State interpretation (Project 2009-17) of "transmission Protection System" and should state: "Protection Systems applied on, or designed to provide protection for a BES Facility and that trips a BES Facility" 3. Applicability, 4.2. - does not reflect the interpretation of Project 20009-10 that excludes non-electrical protection (e.g., sudden pressure relays) and auxiliary relays. Because the definition of Protection System (recently approved) does not clearly exclude "non-electrical" protection, the Applicability section should. For instance, a vibration monitor, steam pressure, etc. protection of generators, sudden pressure protection of transformers, etc. should not be included in the standard. An alternative is to change the definition of Protection System to make sure it only includes electrical 4. Table 1-4 requires a comparison of measured battery internal ohmic value to battery baseline. Battery manufacturers typically do not provide this value and one manufacturer states that the baseline test are to be performed after the battery has been in regular float service for 90 days. It is unclear how to comply with the requirement for the initial 90 days. Additionally, we would recommend that this requirement be modified to permit an entity to establish a “baseline” value based on statistical analysis of multiple test results specific to a given battery manufacturer/model. Several commenters previously expressed their concerns with performing capacity tests. While this may just be an entity’s preference, allowing an entity to establish a baseline at some point beyond the initial installation period would give entities the option of using the internal resistance test in lieu of a capacity test. 5. Small entities with only one or two BES substations may not have enough components to take advantage of the expanded maintenance intervals afforded by a performance-based maintenance program. Aggregating these components across different entities doesn’t seem too logical considering the variations at the sub-component level (wire gauge, installation conditions, etc.) 6. Trip circuits are interconnected to perform various functions. Testing a trip path may involve disabling other features (i.e. breaker failure or reclosing) not directly a part of the test being performed. Temporary modifications made for testing introduce a chance to accidentally leave functions disabled, contacts shorted, jumpers lifted, etc. after testing has been completed. Trip coils and cable runs from panels to breaker can be made to meet the requirements for monitored components. The only portions of the

Organization	Yes or No	Question 5 Comment
		circuitry where this may not be the case is in the inter- and intra-panel wiring. Because such portions of the circuitry have no moving parts and are located inside a control house, the exposure is negligible and should not be covered by the requirements. Entities will be at increased compliance risk as they struggle to properly document the testing of all parallel tripping paths. The interconnected nature of tripping circuits will make it difficult to count the number of circuits consistently for the purpose of calculating a VSL.

Response: Thank you for your comments.

1. **For UFLS and UVLS, the maintenance activities related to station dc supply and control circuitry are somewhat constrained relative to similar activities for Protection Systems in general. Regardless, without proper functioning of these component types, UFLS and UVLS will not respond as expected, and will therefore degrade BES system reliability, particularly during the stressed system conditions for which UFLS and UVLS are installed. Relative to control circuitry, Table 1-5 specifically excludes UFLS and UVLS from maintenance activities relate to the interrupting device trip coil.**
2. **This interpretation is not yet approved by FERC. When this interpretation is approved, the SDT will incorporate it within PRC-005-2**
3. **The recently-balloted revision of the definition of Protection System, which has been approved by the NERC Board of Trustees and will soon be filed with FERC for approval, clearly includes only protective relays that respond to electrical quantities. As for auxiliary relays, the interpretation to which you refer states that they are not explicitly included, but are included to the degree that an entity's Protection System control circuitry addresses them (which has been identified as a reliability gap), and are being added to PRC-005-2 to resolve that gap.**
4. **Typical baseline values for various types of lead-acid batteries can be obtained from the test equipment manufacturer, perhaps the battery vendor, and perhaps other sources for batteries that are already in service. For new batteries, the initial battery baseline ohmic values should be measured upon installation and used for trending.**
5. **Entities are not required to use performance-based maintenance programs. Requirement R3 and Attachment A are provided for the use of entities that can (and desire to) avail themselves of this approach.**
6. **The requirement relative to control circuitry does not explicitly require trip or functional testing of the entire path; it requires that entities verify all paths without specifying the method of doing so. Please see Section 15.5 of the Supplementary Reference Document for a detailed discussion.**

PSEG Companies ("Public Service Enterprise Group Companies")	Yes	1. The facilities listed in 4.2.5.5 include protection systems for "system connected" station service transformers associated with generators that are part of the BES. If a station service transformer is connected to a non BES bus then it would still fall under the PRC5 applicability requirements as written. The FAQs discuss relays associated with station auxiliary loads as not included in the program requirements. The non BES connected transformers should be included in that same category of equipment. 2. From the FAQ's - "Relays which trip breakers serving station auxiliary loads such as pumps, fans, or fuel handling equipment, etc., need not be included in the program even if the loss of the those loads could

Organization	Yes or No	Question 5 Comment
		result in a trip of the generating unit. Furthermore, relays which provide protection to secondary unit substation (SUS) or low switchgear transformers and relays protecting other downstream plant electrical distribution system components are not included in the scope of this program even if a trip of these devices might eventually result in a trip of the generating unit." Suggest the following added details be considered to be consistent with intent of BES connected facilities. Revise Description 4.2.5.5 as follows: "Protection systems for BES system connected station service transformers connected for generators that are part of the BES". 3. With respect to DC supply systems (batteries, chargers),the implementation plan is too aggressive. Some battery checks will have to be done on a 3 month interval, and entities will be required to be compliant with this new frequency in 1 Calendar year. This timeframe is unreasonable and needs to be pushed back to at least 2 years. 4. PSEG is also asking for clarification to the Supplementary reference document: On page 4, section 2.3 it states that the standard is designed to ONLY include "relays that detect a fault on the BES and take action in response to that fault". If PSEG is interpreting this correctly, this is a massive shift from the existing PRC-005-1 standard. The existing PRC-005-1 includes all distribution relays that trip a BES breaker to be part of the scope. In this revision, PRC-005-2 would exclude those distribution relays if they are designed to act for faults on the distribution system. PSEG would fully support this interpretation. PSEG would like this clarified and confirmed. This is very important.
Response: Thank you for your comments. **1. The Applicability of the draft Standard had been revised to remove "system-connected station service transformers".** **2. The FAQs have been merged into the Supplementary Reference Document; this discussion has been revised.** **3. The Implementation Plan for Requirement R4 has been revised to add one year to all established dates.** **4. Section 2.3 of the Supplementary Reference Document has been extensively revised, and the sentence to which you refer is no longer present. As for your comment, "The existing PRC-005-1 includes all distribution relays that trip a BES breaker to be part of the scope," the SDT believes that this is an element of a Regional practice regarding PRC-005-1, and entities should expect to comply with PRC-005 as established within the NERC Standard and further defined by Regional practice.**		
MRO's NERC Standards Review Subcommittee	Yes	1. In the Purpose statement delete "affecting" and replace it with "protecting". The purpose of the standard deals with systems that protect the BES. 2. In sections R1 and R4.2.1 delete "applied on" as unneeded and potentially confusing. The goal is to cover Protection Systems designed to protect the BES.

Organization	Yes or No	Question 5 Comment
		3. The NSRS believes that Article 1.4 needs to be deleted from the standard. It is redundant and serves not purpose. 4. The NSRS believes that Article 1.5 needs to be deleted from the standard. There is a major concern on what an "acceptable parameter" is and how it would be interpreted by the Regional Entities. 5. The NSRS believes that Article 4.2 needs to be deleted from the standard. There is no need for this article if Article 1.5 is deleted. 6. Section 4.2 Applicable Facilities: We are concerned with this paragraph being interpreted differently by the various regions and thereby causing a large increase in scope for Distribution Provider protection systems beyond the reach of UFLS or UVLS.4.2.1 Protection Systems applied on, or designed to provide protection for, the BES. The description is vague and open for different interpretations for what is "applied on" or "designed to provide protection". According to the November 17, 2010 Draft Supplementary Reference page 4, the Standard will not apply to sub-transmission and distribution circuits, but will apply to any Protection System that is designed to detect a fault on the BES and take action in response to the fault. The Standard Drafting Team does not feel that Protection Systems designed to protect distribution substation equipment are included in the scope of this standard; however, this will be impacted by the Regional Entity interpretations of 'protecting" the BES. Most distribution protection systems will not react to a fault on the BES, but are caught up in the interpretation due to tripping a breaker(s) on the BES. 7. Section F Supplementary Reference Documents: The references listed in this section refer to 2009 dates and do not match with the 2010 reference documents supplied for comment. 8. Table 1-4 Component Type Station dc Supply: o "Any dc supply for a UFLS or UVLS system" - This should not tied to the same testing interval as control circuits. The dc supply system is significantly different from control circuits and should have a maximum maintenance period as other dc supplies do. 9. Replace the words "perform as designed" on page 14 of Table 1-4 with "operate within defined tolerances." 10. Table 1-5 Component Type Control Circuitry: a. This table allows for unmonitored trip coils for UFLS or UVLS breakers to have "no periodic maintenance". "Unmonitored control circuitry associated with protective functions" should also have an exclusion for UFLS and UVLS circuitry that would allow for "no periodic maintenance". b. There is a concern that requiring the electrical testing and maintenance of Electromechanical trip or Auxiliary devices will force entire bus outages to be scheduled, which will compromise the BES

Organization	Yes or No	Question 5 Comment
		reliability more by forcing utilities across the US to unnecessarily take multiple non-faulted BES elements out of service. Such testing is also likely to introduce human error that will cause outages such as items outlined in the NERC lessons learned" and therefore such testing will result in more outages than actual failures.

Response: Thank you for your comments.

1. **The "Purpose" is defined by the SAR.**
2. **Requirement R1 and Requirement R4, Part 4.2.1 have been modified as you suggested.**
3. **The SDT disagrees; Requirement R1, Part 1.4 supports Requirement R1, Part 1.2, and seems necessary to assure that entities have appropriately applied the longer intervals associated with monitored components.**
4. **The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. Please see Supplementary Reference Document, Section for a discussion of this. The associated VSL has also been revised.**
5. **The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.**
6. **Applicability 4.2.1 has been revised to remove 'applied on". The SDT believes that this addresses your concern. Applicability 4.2.2 and 4.2.3, respectively, address UFLS and UVLS specifically, and are not related to Applicability 4.2.1. The Supplementary Reference Document has been revised to clarify.**
7. **The date in Clause F of the standard related to the Supplementary Reference Document has been revised.**
8. **The SDT disagrees. Station dc supply for UFLS/UFLS only is limited in its impact, and the SDT believes that using the same intervals as for the related control circuits.**
9. **"Tolerances" does not fully describe the parameters for maintenance of station dc supply; "perform as designed" is far more inclusive.**
10. **a. The SDT intends that tripping of the interrupting device for UFLS/UVLS is not required, but that the other portions of the dc control circuitry still shall be maintained. See Section 15.3 of the Supplementary Reference Document.**

    b. 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

Organization	Yes or No	Question 5 Comment
Western Area Power Administration	No	
TransAlta Centralia Generation Partnership	No	
NextEra Energy	Yes	The draft standard is too prescriptive. 1. Requirement R1, Part 1.5 would be overwhelming if approved. Requirement R1, Part 1.5 should be deleted. 2. Requirement R4, Part 4.2 phrase "established in accordance with Requirement R1, Part 1.5" should be deleted. The standard without these additional requirements would be sufficient to establish that the Protection System is maintained and protects the BES. 3. Table 1-2 Component Type Communications Systems Maximum Maintenance Interval of 3 Calendar Months to verify that the communications system is functional for any unmonitored communications system is unyielding. Most communication failures are caused by power supply failures which Next Era does monitor. Based on experience and monitoring of communication power supplies, 12 calendar months would be adequate. The maximum maintenance interval should be changed from 3 calendar months to 12 calendar months. 4. Table 1-4, Component Type Station dc Supply Maximum Maintenance Interval of 3 Calendar Months to inspect electrolyte levels on “Any unmonitored station dc supply not having the monitoring attributes of a category below. (excluding UFLS and UVLS)” is too stringent. Verifying battery charger float voltage every 18 calendar months is sufficient to prevent excessive gassing and water loss of battery cells. The maximum maintenance interval should be changed from 3 calendar months to 6 calendar months. 5. Table 1-4, Component Type Station dc Supply Maximum Maintenance Interval of 3 Calendar Months to measure the internal ohmic values on “Unmonitored Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries that does not have the monitoring attributes of a category below. (excluding UFLS and UVLS)” is too stringent. With the standard’s requirement to verify the float voltage every 18 calendar months, measuring the internal ohmic values every 6 calendar months would be adequate. The maximum maintenance interval should be changed from 3 calendar months to 6 calendar months.

Response: Thank you for your comments.

1. **The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to**

Organization	Yes or No	Question 5 Comment
address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this. **2. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.** **3. The activity to which you refer is an inspection-based activity based on overall functionality, and addresses functionality of various communications technologies. If an entity monitors the power supply (as suggested), doing so addresses one portion of the functionality, but does not address channel integrity, etc.** **4. The SDT disagrees, and believes that the specified activities, at the specified intervals, are appropriate.** **5. Table 1-4(b) has been revised as you suggested.**		
City of Austin DBA Austin Energy	Yes	1. The Requirement R1.5. is vague and the intent is not well understood. We recommend it be rewritten to clarify the intent. 2. In the Requirement R2. the phrase "... shall verify those components possess the monitoring attributes ..." is too vague and not easily understandable. We recommend this requirement be rewritten.
Response: Thank you for your comments. **1. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.** **2. The SDT had concluded that Requirement R2 is redundant with Requirement R1, Part 1.4, and has deleted Requirement R2 (together with the associated Measure and VSL).**		
PacifiCorp		
Southern Company Transmission	Yes	1. Page 5, 4.2. ("or initiate resolution") Comment ->> Standard does not specify to "follow through" to completion. Is record of completion required? 2. Page 5, 1.5. (1.5. Identify calibration tolerances or other equivalent parameters for each Protection System component type that establish acceptable parameters for the conclusion of maintenance

Organization	Yes or No	Question 5 Comment
		activities.) Comment ->> This is too vague, broad, general and all encompassing. For example, what is the calibration tolerance for “control circuitry” which is made up of many things such as wiring, auxiliary relays, trip coils, etc. We currently have calibration tolerances on electromechanical relays but not on all components of a protection system (communications systems, voltage and current sensing devices, station dc supply, control circuitry). To try to identify calibration tolerances or other equivalent parameters for each of these components would be extremely difficult and time consuming. Clarification is needed on what components or parts of components require calibration tolerances. Another option is to remove this requirement. 3. Page 5, 4.5. (4.2. Either verify that the components are within the acceptable parameters established in accordance with Requirement R1, Part 1.5 at the conclusion of the maintenance activities, or initiate resolution of any identified maintenance correctable issues.)Comment ->> See comments above on 1.5. Clarification is needed on what is required to verify that the components are within acceptable parameters. We feel it should be adequate to provide a simple way to verify this requirement such as to include this in our maintenance procedure (equipment is to be left within tolerance), provide closed work order, show “checked” check box, provide a simple statement that this was completed, or etc. We feel that having to provide detailed data such as “as found” / “as left” values is too complicated and time consuming. Please clarify or consider removing this requirement. 4. Page 6, M.4. (“and initiated resolution”) Comment ->> Standard does not specify to “follow through” to completion. Is record of completion required? 5. Page 10, F.1 (July 2009) & F.2 (DRAFT 1.0 - June 2009) Comment ->> Need new dates and draft number. 6. Page 11 (For microprocessor relays, verify operation of the relay inputs and outputs that are essential ...) Comment ->> Does this require changing the state of the input contacts or can you just jumper voltage to the inputs and verify that the microprocessor relays acknowledged the change? 7. Page 17 (“Verify electrical operation(1)of EM trip and auxiliary devices(2).”) Comment ->> (1) Is it required to verify that trip and auxiliary device contacts change state? If so, please state as a requirement.(2) We recommend that this requirement only includes EM aux LO / tripping relays that trip interrupting devices directly. Other EM aux relays such as BFI aux. relays should be excluded. Please state this clearly in the Standard. Note that these aux relays such as BFI aux relays are included

Organization	Yes or No	Question 5 Comment
		in the “unmonitored control circuitry associated with protective functions” requirement and will be verified on a 12 year interval. (3) Please consider including an elementary diagram to show what is included. 8. Page 17 (Verify all paths of the control and trip circuits.) Comment ->> Clarification needed. Is it required to perform a full functional test, i.e. trip breakers? Or is reading DC across trip contacts all that is required? 9. Page 14 (Table 1.4) Change the maintenance interval for unmonitored station dc supply from “3 Calendar Months” to “4 times annually”. This facilitates compliance to the standard by creating completion milestones for batteries at the end of each quarter of the year. 10. Page 15 (Table 1.4The standard requires the establishment of a battery baseline for cell/unit internal ohmic values and the comparison of impedance readings every 18 calendar months to that baseline. Due to the lack of original impedance readings at the time of installation of the battery. Since in many cases no such data is available; it needs to be made clear that establishing a baseline from , from manufacturer’s data, the most recent impedance test, or the first impedance test completed after the adoption of the new standard is acceptable

Response: Thank you for your comments.

1. **No. Full resolution of maintenance correctable issues may require extensive work; the SDT intends that INITIATION of the resolution is all that is required per PRC-005-2.**
2. **The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.**
3. **The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.**
4. **No. Full resolution of maintenance correctable issues may require extensive work; the SDT intends that INITIATION of the resolution is all that is required per PRC-005-2.**
5. **The date has been revised.**
6. **The SDT believes that it would be sufficient to apply voltage to the input and observe that the relay responds accordingly.**
7. **1 – “Verify” means “Determine that the component is functioning correctly”. The SDT intends that the device be electrically operated, but not that**

Organization	Yes or No	Question 5 Comment
additional verification be conducted during the electrical operation. However, the 12-year activity for unmonitored control circuitry would require verification of full functionality, including all of the related contacts. 2- The standard has been modified in consideration of your comment. 3 – An elementary diagram would be inappropriate in the standard. Additionally, the design of the control circuitry varies so widely from one application to another that it seems (to the SDT) that it would not be effective to include such an example in the Supplementary Reference Document. **8. The control circuitry can be tested in overlapping segments. It seems to the SDT that it is not necessary to trip the breakers with the functional test, as long as the entity performs the activities necessary to demonstrate that all overlapping segments will function properly.** **9. The SDT believes that your suggestion would not be effective in assuring periodic maintenance of the dc supply.** **10. The station battery baseline value is up to the entity to determine. Please see Clause 15.4.1 of the Supplementary Reference Document for a discussion of this.**		
Clark Public Utilities	No	
Exelon	Yes	1. In response to Exelon's comments provided to drafts 1 and 2 of PRC-005, the SDT did not explain why a conflict with an existing regulatory requirement is acceptable. The SDT responded that a conflict does not exist and that the removal of grace periods simply is there to comply with FERC Order directive 693. This response does not answer or address dual regulation by the NRC and by the FERC. Specifically, the request has not been adequately considered for 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 become non-compliant with PRC-005. Therefore, Exelon requests that the SDT communicate with the NRC and with the FERC to ensure a conflict of dual regulation is not imposed on a nuclear generating unit without the necessary evaluation. 2. In addition, although Exelon Nuclear agrees with 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 be integrated within the plant's routine 18 month to 2 year interval refueling outage schedule, the SDT has not considered that nuclear refueling outages may be extended past the 18 month to 2 year "normal" periodicity. There are some unique factors related to nuclear generating units that the SDT has not taken into consideration in that these units are typically online continuously between refueling outages without shutting down for any other required maintenance. Historically, generating units have at times extended planned refueling outage shutdown dates days and even weeks due to requests from transmission operations, fuel issues and electrical demand. Without the grace period exclusion currently allowed by existing maintenance programs, a nuclear plant will be forced to either extend outage duration to include testing on an every other refueling outage (i.e., every four years to ensure compliance for a typical boiling water reactor) or leave the testing on a six year periodicity with the vulnerability of a forced shut down simply to perform maintenance to meet the six year periodicity

Organization	Yes or No	Question 5 Comment
		or a self report of non-compliance. To ensure compliance, the nuclear industry will be forced to schedule battery testing on a four year periodicity to ensure the six year periodicity is met, thus imposing a requirement on nuclear generating units that would not apply to other types of generating units. 3. In addition, Exelon has the following technical comments a. Sections 4.2.5.4 and 4.2.5.5 need to clearly state that only protection which affects the BES is within the scope of the PRC-005. b. There is not enough clarity in the statement “each protection system component type” for one to stay at the component level vs. dropping to sub-component level. If sub-components reviews are required, the effort becomes unmanageable. Therefore the Standard should identify calibration tolerances or other equivalent parameters. Suggest rewording to "each protection system major component type”
Response: Thank you for your comments. **1. If several different regulatory agencies have differing requirements for similar equipment, it seems that the entity must be compliant with the most stringent of the varying requirements. In the cited case, an entity may need to perform maintenance more frequently than specified within the requirements to assure that they are compliant.** **2. The 18-month (and shorter) interval activities are activities that can be completed without outages – primarily inspection-related activities. An entity may need to perform maintenance more frequently than specified within the requirements to assure that they are compliant.** **3. a. Applicability 4.2.5.5 has been removed. Generator-connected station service transformers are essential to the continuing operation of the generating plant; therefore, protection on these system components is included within PRC-005-2 if the generation plant is a BES facility.** **b.The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.**		
Manitoba Hydro	Yes	1) We disagree with the requirements for battery maintenance outlined in table 1-4. In particular the requirement for a 3 month check on electrolyte level seems too frequent based on our experience. We would like to point out that although IEEE std 450 (which seems to be the basis for table 1-4) does recommend intervals it also states that users should evaluate these recommendations against their own operating experience. 2) Also, the Implementation Plan is not consistent for areas requiring regulatory approval and areas requiring regulatory approval. The 6 month time frame proposed for R1 for areas not requiring regulatory approval is not achievable and is not consistent with areas requiring regulatory approval. To be consistent, the effective

Organization	Yes or No	Question 5 Comment
		date for R1 in jurisdictions where no regulatory approval is required should be the first day of the first calendar quarter 12 months after BOT approval.
Response: Thank you for your comments. **1. The SDT believes that the 3-month interval specified in the standard is appropriate.** **2. In consideration of your comment, "6" has been modified to "12" in the Implementation Plan for Requiremnet R1.**		
Dynegy Inc.	Yes	For R1.5, we feel to much is being asked for since this information is not easilly controlled and the tolerances vary over time.
Response: Thank you for your comments. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.		
Oncor Electric Delivery Company LLC	Yes	Comment A: Oncor believes that Requirement R1 Part 1.5 of this Standard should be removed. It is too vague, intrusive, and divisive for what it brings to the reliability of the BES. Specifically it burdens all Transmission Owners, Generation Owners or Distribution Providers with the impossible task of having to "identify calibration tolerances or other equivalent parameters for each Protection System component type that establish acceptable parameters for the conclusion of maintenance activities." By definition a Protection System component type is "any one of the five specific elements of the Protection System definition" and "a component is any individual discrete piece of equipment included in a Protection System, such as a protective relay or current sensing device." What Requirement R1 part 1.5 with its associated High VSL in the Standard would decree is that all Transmission Owners, Generation Owners and Distribution Providers who "failed to establish calibration tolerance or equivalent parameters to determine if every individual discrete piece of equipment in a Protection System is within acceptable parameters" would be in violation of the Standard - with a High VSL. Oncor with over 98 years of Protection System maintenance experience feels that most Owners including itself would be non-compliant with this unclear, meddling and disruptive requirement no matter how long the implementation plan for the Standard is. Comment B: Oncor believes that in light of Comment "A" above Requirement R4 Part 4.2 must be modified to remove all references to Requirement R1 Part 1.5 of the Standard. The new requirement should be modified to read "Either verify that the components are within acceptable parameters at the conclusion of the maintenance activities or initiate any necessary activities to correct maintenance correctable issues." Also in order to assist both the owners and the compliance authorities who may question how one verifies that the components are within acceptable parameters the FAQ document should be modified to discuss how many

Organization	Yes or No	Question 5 Comment
		utilities are doing this with results that indicate either a pass or fail certified by the qualified persons performing maintenance. Comment C: Oncor feels that the wording "no less frequently than" found in Requirement R4 Parts 4.1.1 and 4.1.2 should be chanced back to the wording in the previous version of the Standard "not to exceed." Comment D: Oncor recommends that in light of Comment "A" above Measure M1 be modified to remove all reference to Requirement R1 Part 1.5. Comment E: Oncor, as stated in Comment "B" above, recommends that the FAQ document be modified to provide more information on what could be used for evidence that the Transmission Owner, Generation Owner or Distribution Provider has "initiated resolution of identified maintenance correctable issues." This will assist both the owners and the compliance authorities in answering the question of what constitutes proof that a maintenance correctable issue was identified. Comment F: The second and third paragraphs added under Compliance 1.3 Data Retention provide more information as to what data is required to be retained. Oncor feels that these two paragraphs will help the compliance authorities, the Transmission Owners, Generation Owners and Distribution Providers needed guidance of what is required for data retention.

Response: Thank you for your comments.

A. **The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.**

B. **The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.**

C. **"No less frequently than" was adopted on recommendation of NERC Staff as the preferred method of addressing this requirement.**

D. **The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.**

E. **The SDT has decided to eliminate the FAQ and incorporate topics and discussion from the FAQ within the Supplementary Reference Document. Your comments will be considered within that activity.**

Organization	Yes or No	Question 5 Comment
F. Thank you for your comment.		
Ingleside Cogeneration LP		The latest version of PRC-005-2 includes a new requirement (R1.5) to identify calibration tolerances or equivalent parameters that must be verified before a maintenance activity is considered complete. Although we understand the project team's intent, Ingleside Cogeneration LP is concerned that this requirement will lead to multiple interpretations of which tolerances or parameters are the most important. In addition, audit teams may expect to see certain values based upon their own sense of reliability. This is exactly the ambiguity that PRC-005-2 is trying to eliminate. In addition, calibration tolerances and reliability parameters may vary by equipment manufacturer or by configuration. It is not clear that documenting every scenario to demonstrate regulatory compliance is a benefit to BES reliability.
Response: Thank you for your comments. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.		
Indiana Municipal Power Agency	Yes	Standard PRC-005-2 Draft 3 contains a section of "Definitions of Terms Used in Standard" that includes newly defined or revised terms uses in this proposed standard. There are a number of references made to these Terms in the Standard that are not capitalized. IMPA would propose that anywhere that the terms included in the "Definition of Terms Used" are used in the standard that they be capitalized. When any word is not capitalized in a standard then the common practice is to use the Webster Dictionary meaning. IMPA does not know why the SDT is reluctant to put these terms in the NERC Glossary of Terms, but by putting the terms in the glossary it would eliminate any confusion. When these terms are capitalized all registered entities will know that these are defined terms and will be able to consistently apply the definition without confusion. For example: 1.1 Address all Protection System component types would become1.1 Address all Protection System Component Types. If these terms are not capitalized in the standard (meaning they are not referring to the defined term) then the meaning of these terms could vary not only from utility to utility but also from Region to Region.
Response: Thank you for your comments. The standard capitalizes defined terms only when they refer to terms which are (or will be) in the NERC Glossary of Terms. Terms will generically be capitalized when appearing at the beginning of a sentence or within a title, in accordance with common editorial practice. If the terms were placed in the Glossary of Terms, the SDT is concerned that some future SDT, in order to utilize these terms, may change them in a fashion inconsistent with the intended usage within PRC-005-2.		

Organization	Yes or No	Question 5 Comment
South Carolina Electric and Gas		
Entergy Services	Yes	Adding Requirement 1.5 is a significant revision and raises questions as to how broadly an accuracy or equivalent parameter requirement and associated documentation would need to be addressed by entities and/or will be measured for compliance. Discussion on this new requirement does not seem to be addressed anywhere in the FAQ or Supplementary Reference documents. Additionally, to the best of our knowledge, the need for such a requirement was not brought up as a concern or comment on the prior draft version of this standard, and in the context of a requirement need, we don't believe it has been attributed to or actually poses any significant reliability risk. We do not believe this requirement is justified.
Response: Thank you for your comments. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.		
Duke Energy	Yes	1. We have previously commented that the FAQ and Supplementary Reference documents should be made part of this standard. If that cannot be done, then more of the information in those documents needs to be included in the requirements in the standard to provide clarity. Compliance will only be measured against what is in the standard, and we need more clarity. 2. R1.4 and R1.5 need more information to provide clarity for compliance. It's unclear to us what the expectation is for compliance documentation for "monitoring attributes and related maintenance activities" in R1.4 and "calibration tolerances or other equivalent parameters" in R1.5. This is fairly straightforward for relays, but not for other component types. Either provide clarity or delete these requirements. 3. R4.2 - it is critical that more clarity be provided for R1.5 so that we can also understand what the compliance expectation is for R4.2 4. M4 - Need to clarify that these pieces of evidence are all "or", not "and" (i.e. any of the listed examples are sufficient for compliance). We reiterate the need for additional clarity on R1.5 and R4.2 such that compliance can be demonstrated for all component types. 5. Table 2 - We are fairly clear on the expectation for relays, but need more clarity on the expectation for other component types. Also, need to change the phrase "corrective action can be taken" to "corrective action can be initiated", consistent with the Supplementary Reference document.
Response: Thank you for your comments.		

Organization	Yes or No	Question 5 Comment
1. The SDT has decided to eliminate the FAQ and incorporate topics and discussion from the FAQ within the Supplementary Reference Document. The SDT believes that entities should be able to implement the standard without the Supplementary Reference. However, the SDT is also convinced that many entities may find the supporting discussion/rationale/etc useful, particularly to assist them in implementing the standard in an efficient manner. **2. Requirement R1, Part 1.4 has been modified for clarity. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.** **3. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.** **4. The SDT has provided examples of the sort of evidence that may serve to demonstrate compliance. The degree to which any single evidence type is sufficient is dependent on the completeness of the evidence itself. The Measure has been modified to clarify this point.** **5. Table 2 has been modified to be clearer. "Taken" has been replaced with "initiated" in consideration of your comment.**		
Wisconsin Electric Power Company		
Independent Electricity System Operator	Yes	1. Requirement R1, Part 1.5 is vague and needs clarification. It is not clear what "Identify calibration tolerances or other equivalent parameters" means and this may be subject to different interpretations by entities and compliance enforcement personnel. 2. Additionally, in the Implementation plan for Requirement R1, we recommend changing "six" to "fifteen" to restore the 3-month time difference between the durations of the implementation periods for jurisdictions that do and don't require regulatory approval, which existed in the previous draft. This change will ensure equity for those entities located in jurisdictions that do not require regulatory approval as is the case here in Ontario. More importantly it supports the IESO's strong belief in the principle that reliability standards should be implemented in an orderly and coordinated fashion across regions to ensure system reliability is not compromised.
Response: Thank you for your comments. **1. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference**		

Organization	Yes or No	Question 5 Comment
Document, Section 8 for a discussion of this. 2. In consideration of your comment, "6" has been modified to "12" in the Implementation Plan for Requirement R1.		
American Electric Power		1. Standards Requirement 1.5 and the reference to R1.5 in Requirement 4.2 should be removed. Specifying calibration tolerances for every protection system component type, while a seemingly good idea, represents a substantial change in the direction of the standard. It would be very onerous for companies to maintain a list of calibration tolerances for every protection system component type and show evidence of such at an audit. AEP believes entities need the flexibility to determine what acceptance criteria is warranted and need discretion to apply real-time engineering/technician judgment where appropriate. 2. Three different types of maintenance programs (time-based, performance-based and condition-based) are referenced in the standard or VSLs, yet the time-based and condition-based programs are neither defined nor described. Certain terms defined within the definition section (such as Countable Event or Segment) only make sense knowing what those three programs entail. These programs should be described within the standard itself and not assume knowledge of material in the Supplementary Reference or FAQ. 3. "Protective relay" should be a defined term that lists relay function for applicability. There are numerous 'relays' used in protection and control schemes that could be lumped in and be erroneously included as part of a Protection System. For example, reclosing or synchronizing relays respond to voltage and hence could be viewed by an auditor as protective relays, but they in fact perform traditional control functions versus traditional protective functions. 4. The Data Retention requirement of keeping maintenance records for the two most recent maintenance performances is a significant hurdle for any owners to abide by during the initial implementation period. The implementation plan needs to account for this such that Registered Entities do not have to provide retroactive testing information that was not explicitly required in the past.
Response: Response: Thank you for your comments. 1. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this. 2. The term, "condition-based" has been removed from the draft standard. The other terms are used, but are clear in the context in which they are used. 3. "Protective relay" is defined by IEEE, and the SDT sees no need to either change the definition or to repeat the definition within PRC-005. Further,		

Organization	Yes or No	Question 5 Comment
the applicability of generically-described protective relays is defined by the Applicability clause of PRC-005-2. **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 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. This seems to be consistent with the current practices of several Regional Entities.**		
ITC	Yes	1. We would like some further clarification on PRC-005-2 Draft 3, specifically on the statement in Table 1-4 for unmonitored station DC supply with VLA batteries. In the table it is mentioned that we are to perform either a capacity test every six years or verify that the station battery can perform as designed by evaluating the measured cell/unit internal ohmic values to station battery baseline, the latter statement is a little vague and needs further clarification with regards to the expectations from the standard. Please describe an acceptable method of establishing a baseline “measured cell/unit internal ohmic value” We would like to know what exactly is required. We measure the cell internal ohmic value on an annual basis every 12 months, is that enough? What are the comparison parameters with regards to battery baseline? At what percent should we look to replace the cell? 2. Is a battery system that only supplies the SCADA RTU considered part of the protective system if alarms for the monitored protective systems utilize that SCADA RTU?
Response: Response: Thank you for your comments. **1. The station battery baseline value is up to the entity to determine. Please see Section 15.4.1 of the Supplementary Reference for a discussion of this.** **2. No. The Applicability of the standard limits the standard to only those devices within the Protection.**		
ISO New England Inc.		1. In general, the standard is overly prescriptive and complex. It should not be necessary for a standard at this level to be as detailed and complex as this standard is. Entities working with manufacturers, and knowledge gained from experience can develop adequate maintenance and testing programs. 2. Why are “Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, pressure, seismic, thermal or gas accumulation)...” not included? The output contacts from these devices are oftentimes connected in tripping or control circuits to isolate problem equipment. 3. Due to the critical nature of the trip coil, it must be maintained more frequently if it is not monitored. Trip coils are also considered in the standard as being part of the control circuitry. Table 1-5 has a row labeled “Unmonitored Control circuitry associated with protective functions”, which would include trip coils,

Organization	Yes or No	Question 5 Comment
		has a "Maximum Maintenance Interval" of "12 Calendar Years". Any control circuit could fail at any time, but an unmonitored control circuit could fail, and remain undetected for years with the times specified in the Table (it might only be 6 years if I understand that as being the trip test interval specified in the table). Regardless, if a breaker is unable to trip because of control circuit failure, then the system must be operated in real time assuming that that breaker will not trip for a fault or an event, and backup facilities would be called upon to operate. Thus, for a line fault with a "stuck" breaker (a breaker unable to trip), instead of one line tripping, you might have many more lines deloaded or tripped because of a bus having to be cleared because of a breaker failure initiation. The bulk electric system would have to be operated to handle this contingency. 4. In reference to the FAQ document, Section 5 on Station dc Supply, Question K, clarification is needed with respect to dc supplies for communication within the substation. For example, if the communication systems were run off a separate battery in separate area in a substation, would the standard apply to these batteries or not? 5. To define terms only as they are used in PRC-005-2 is inviting confusion. Although they may be unique to PRC-005-2, some or all of them may be used in future standards, some already may be used in existing standards, and may or may not be deliberately defined. Consistency must be maintained, not only for administrative purposes, but for effective technical communications as well. 6. What is the definition of "Maintenance" as used in the table column "Maximum Maintenance Interval"? Maintenance can range from cleaning a relay cover to a full calibration of a relay. 7. A control circuit is not a component, it is made up of components. 8. Sub-requirement 1.5 needs to be clarified. It is not clear what "Identify calibration tolerances or other equivalent parameters..." means, and may be subject to different interpretations by entities and compliance enforcement personnel. 9. In the Implementation plan for Requirement R1, recommend changing "six" to fifteen. This change would restore the 3-month time difference that existed in the previous draft, between the durations of the implementation periods for jurisdictions that do and do not require regulatory approval. It will ensure equity for those entities located in jurisdictions that do not require regulatory approval, as is the case in Ontario. 10. The 'box' for "Monitored Station dc supply..." in Table 1-4 is not clear. It seems to continue to the next page to a new box. There are multiple activities without clear delineation.

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

Organization	Yes or No	Question 5 Comment
compliance. Further, FERC Order 693 directs NERC to establish maximum allowable intervals, which implies that minimum activities also need be prescribed. If an entities' experience is that components require less-frequent maintenance, a performance-based program in accordance with R3 and Attachment A is an option. 2. The SDT concentrated their efforts on protective relays which use the entire group of component types within the Protection System definition. Also, there is currently no technical basis for the maintenance of the devices which respond to non-electrical quantities on which to base mandatory standards related either to activities or intervals. Absent such a technical basis, we are currently unable to establish mandatory requirements, but may do so in the future if such a technical basis becomes available. 3. According to Table 1-5, trip coils of interrupting devices must be verified to operate every 6 years, rather than the 12-year interval. You are free to maintain these devices more frequently if you desire. 4. With respect to dc supply associated only with communications systems, we prescribe, within Table 1-2, that the communications system must be verified as functional every 3 months, unless the functionality is verified by monitoring. The specific station dc supply requirements (Table 1-4) do not apply to the dc supply associated only with communications systems. The SDT has decided to eliminate the FAQ and incorporate topics and discussion from the FAQ within the Supplementary Reference Document. Your comments will be considered within that activity. 5. The SDT has proposed these terms for use only within PRC-005-2 because we are concerned that other uses of these terms, either now or in the future, may not be consistent with the terms as used here. They are defined only for clarify within this standard. The SDT will confirm with NERC staff that this approach is acceptable. 6. As used in the "Maximum Maintenance Interval" column title of the table, maintenance refers to whatever activities are specified in the Activities column. The term is capitalized in the column title in conformance with normal editorial practice as a title, rather than as a definition 7. For purposes of this standard, the control circuit IS defined as one component type. 8. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this. 9. In consideration of your comment, "six" has been modified to "twelve" in the Implementation Plan for Requirement R1, making it consistent with the remainder of the Implementation Plan. 10. Table 1-4 has been further modified for clarity		
Nebraska Public Power District	Yes	Definitions: 1. The PSMP definition inappropriately extends the maintenance program to include corrective maintenance. The first bullet of the Detailed Description section of the SAR specifically states: "Analysis of correct operations or misoperations may be an integral part of condition-based maintenance processes, but need not be mandated in a maintenance standard." The comment in the SAR was

Organization	Yes or No	Question 5 Comment
		directed toward the Purpose of PRC-017 since it is the only one of the applicable PRC standards that included corrective measures in its Purpose. However, the concept of not including corrective maintenance in a maintenance standard should apply to all of the applicable PRC standards. The same statement from the SAR identified above was also included in the NERC SPCTF Assessment of Standards referenced in the SAR. Neither the SAR nor the NERC SPCTF Assessment of the Standards identified the need to expand the maintenance and testing program to include corrective maintenance. I recommend deleting the words "and proper operation of malfunctioning components is restored." from the first sentence of the PSMP definition. I believe that failure to do so exceeds the scope of the SAR. 2. The definition of a Countable Event should clearly state whether or not multiple conditions on a single component will count as a single Countable Event or as multiple Countable Events. For example, a single relay fails its undervoltage setting and its under frequency setting. Is this one Countable Event or two Countable Events? 3. Applicability Part 4.2.2:The ERO does not establish underfrequency load-shedding requirements. Those requirements will be established by Reliability Standard PRC-006-1 when it is approved by FERC. I recommend changing Accountability Part 4.2.2. to "...installed to provide last resort system preservation measures." (Note this wording is consistent with the Purpose of PRC-006-0.)Applicability Part 4.2.5.4 and 4.2.5.5: 4. Station Service transformers provide energy to plant loads and not the BES. If these plant transformers are included, why not include the rest of the plant systems? I recommend deleting Applicability Part 4.2.5.4 and 4.2.5.5. 5. Requirement R1 Part 1.2: The wording of the first sentence is unclear about what information is required. For example, I could state in my PSMP that: "All Protection System component types are addressed through time-based, performance-based, or a combination of these maintenance methods" and be compliant with the Requirement. I recommend re-wording the first sentence to state: "Identify which maintenance method is used to address each Protection System component type. Options include time-based, performance-based (per PRC-005 Attachment A), or a combination of time-based and performance-based (per PRC-005 Attachment A)." Note that PRC-005 Attachment A does not address a combination of maintenance methods and therefore the second reference in the first sentence should be removed if the original wording is retained. 6. Requirement R1 Part 1.4: The column titles in Tables 1-1 through 1-5 have been revised to “Component Attributes” and “Activities”. I recommend changing "monitoring attributes" to "component attributes" and "maintenance activities" to "activities" to be consistent with the Tables. 7. Requirement R1 Part 1.5: Maintenance acceptance criteria for a given Protection System component type may very depending on the manufacturer, model, etc.. Including all acceptance criteria in the PSMP

Organization	Yes or No	Question 5 Comment
		document will over-complicate the program document. I recommend clarifying Part 1.5 to allow the incorporation of device-specific acceptance criteria in the applicable evidentiary documentation. One possible option is to add a second sentence as follows: "The calibration tolerances or other equivalent parameters may be included with the maintenance records." Note that a personal preference would be to use the phrase “acceptance criteria” instead of “calibration tolerances or other equivalent parameters”. 8. Requirement R4:The PSMP definition inappropriately extends the maintenance program to include corrective maintenance. The first bullet of the Detailed Description section of the SAR specifically states: "Analysis of correct operations or misoperations may be an integral part of condition-based maintenance processes, but need not be mandated in a maintenance standard." The comment in the SAR was directed toward the Purpose of PRC-017 since it is the only one of the applicable PRC standards that included corrective measures in its Purpose. However, the concept of not including corrective maintenance in a maintenance standard should apply to all of the applicable PRC standards. The same statement from the SAR identified above was also included in the NERC SPCTF Assessment of Standards referenced in the SAR. Neither the SAR nor the NERC SPCTF Assessment of the Standards identified the need to expand the maintenance and testing program to include corrective maintenance. I recommend deleting the words "including identification of the resolution of all maintenance correctable issues" from the first sentence of the Requirement. I believe that failure to do so exceeds the scope of the SAR. 9. Requirement R4 Part 4.2: What is considered sufficient verification of parameters? Does this require an engineer or technician signature or simply an indication of pass/fail? The PSMP definition inappropriately extends the maintenance program to include corrective maintenance. The first bullet of the Detailed Description section of the SAR specifically states: "Analysis of correct operations or misoperations may be an integral part of condition-based maintenance processes, but need not be mandated in a maintenance standard." The comment in the SAR was directed toward the Purpose of PRC-017 since it is the only one of the applicable PRC standards that included corrective measures in its Purpose. However, the concept of not including corrective maintenance in a maintenance standard should apply to all of the applicable PRC standards. The same statement from the SAR identified above was also included in the NERC SPCTF Assessment of Standards referenced in the SAR. Neither the SAR nor the NERC SPCTF Assessment of the Standards identified the need to expand the maintenance and testing program to include corrective maintenance. I recommend re-wording Requirement 4, Part 4.2 to state: "Verify that the components are within the acceptable parameters established in accordance with Requirement R1, Part 1.5 at the conclusion of the maintenance activities." I believe that failure to do so exceeds the scope of the SAR. 10. Measurement M2: Can a single specification document suffice for similar relay types such as one document for SEL relays? For trip circuit monitoring can a standard document be used for a group of

Organization	Yes or No	Question 5 Comment
		similar schemes ? 11. Measurement M4:I assume this is not an all inclusive list of potential forms of evidence. Please clarify what is meant by "such as". Does this mean that: 1) Any one item is sufficient?; 2) Certain combinations of evidence are necessary? If so, what combinations?; 3) Are other items that are not identified here acceptable? 12. Measurement M4 repeatedly refers to "dated" evidence. However, current audit expectations include either performer signatures or initials on the evidence in addition to the dates. Please revise Measurement M4 to clearly state the expectations regarding performer signatures or initials on the evidence documents. 13. The PSMP definition inappropriately extends the maintenance program to include corrective maintenance. The first bullet of the Detailed Description section of the SAR specifically states: "Analysis of correct operations or misoperations may be an integral part of condition-based maintenance processes, but need not be mandated in a maintenance standard." The comment in the SAR was directed toward the Purpose of PRC-017 since it is the only one of the applicable PRC standards that included corrective measures in its Purpose. However, the concept of not including corrective maintenance in a maintenance standard should apply to all of the applicable PRC standards. The same statement from the SAR identified above was also included in the NERC SPCTF Assessment of Standards referenced in the SAR. Neither the SAR nor the NERC SPCTF Assessment of the Standards identified the need to expand the maintenance and testing program to include corrective maintenance. I recommend deleting the words: "and initiated resolution of identified maintenance correctable issues" from the last sentence of Measurement M4. I believe that failure to do so exceeds the scope of the SAR 14. .Compliance Part 1.3: Tables 1-1 through 1-5 refers to time-based maintenance programs. I recommend changing "performance-based" to "time-based" in the last sentence of the third paragraph. 15. The last paragraph of Part 1.3 of the Compliance Section states: "The Compliance Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent compliance records." This appears to be a requirement of the Compliance Enforcement Authority however they are not identified in Section 4 Applicability of the Standard. It is also in conflict with the SAR Attachment B - Reliability Standard Review Guidelines which states on page SAR-10: "Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity." I recommend deleting the last paragraph of Part 1.3 of the Compliance Section to avoid conflict with the SAR. 16. Table 1-1: The Activity of row 1 states: “Verify operation of the relay inputs and outputs that are essential to ...” Please clarify what is meant by “operation of” the relay inputs and outputs. What is the criteria to determine if something is “essential”? The first line of row 2 has a double colon. Please delete one of

Organization	Yes or No	Question 5 Comment
		them. 17. For the second bullet of row 2 column 1, please clarify what is meant by the last part of this sentence "that are also performing self monitoring and alarming" and how it relates to the voltage and current sampling required. It appears the self monitoring is required in the first bullet. 18. For the first bullet of row 2 column 3, many relay settings may not be essential to the protective function of the relay. I recommend revising the first bullet to: "Settings that are essential to the proper function of the protection system are as specified." 19. The format of the Activities column for all three rows is different. Please reformat them to be consistent. My preference is the second row. 20. Table 1-2: Row 1 Column 2, verifying the functionality of communications systems on a 3 calendar months basis is excessive and unnecessary. Suggest changing the Maximum Maintenance Interval to either 6 calendar months or semi-annual. 21. Row 2 Column 1, please provide examples of typical communications systems that fit into this category, e.g. Mirror Bit or Guard systems? 22. The words "such as" are used repeatedly. Please clarify what is meant by "such as". Is this left up to the Utility to define in their PSMP? 23. Table 1-5: The Activity for row 1 requires verification that each trip coil is able to operate the device. If a control circuitry contains multiple trip coils, it is not always possible to determine which trip coil energized to trip the device. I recommend changing "each trip coil" to "at least one trip coil". 24. Please clarify what is meant by an "Electromechanical trip" device in row 3. 25. Row 3 column 3, does this mean verify the trip contact on the device operates properly but not verify the trip circuit wiring from this contact to the trip coil since the trip circuit is tested in the row below? It is difficult to separate the meaning in these two rows. 26. Row 4 column 3 requires verification of all paths of the control and trip circuits. Please clarify if this includes the control circuitry of Protection Systems located at the other end of a line if the device utilizes a remote trip scheme?

Response: Response: Thank you for your comments.

1. **Corrective maintenance is included within PRC-005-2 only in that the initiation of resolution of maintenance-correctable issues (discovered during maintenance activities) is included. The SDT considers this inclusion to be appropriate and necessary as part of the maintenance program.**

Organization	Yes or No	Question 5 Comment
2. The example cited would be one countable event. The definition has been modified to clarify. 3. Underfrequency load shedding requirements, whether established by Regional Entities (current practice) or by NERC, are ERO requirements. 4. Clause 4.2.5.5 has been removed. Generator-connected station service transformers are essential to the continuing operation of the generating plant; therefore, protection on these system components is included within PRC-005-2 if the generation plant is a BES facility. 5. Requirement R1, Part 1.2 has been modified essentially as you suggest. 6. "Monitoring attributes" are used within the respective tables; "Component attributes" can include monitoring or not. The Tables have been revised to specify "Maintenance Activities". 7. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this. 8. Corrective maintenance is included within PRC-005-2 only in that the initiation of resolution of maintenance-correctable issues (discovered during maintenance activities) is included. The SDT considers this inclusion to be appropriate and necessary as part of the maintenance program. 9. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this. 10. Yes. However, the degree to which any single evidence type is sufficient is dependent on the completeness of the evidence itself. The Measure has been modified to clarify this point. The Measure M2 to which you refer has been deleted in conjunction with the deletion of the accompanying requirement. 11. Yes. The SDT has provided examples of the sort of evidence that may serve to demonstrate compliance. The degree to which any single evidence type is sufficient is dependent on the completeness of the evidence itself. "Such as" was not intended to be an all-inclusive list; additional examples are provided in Section 15.7 of the Supplementary Reference Document. The Measure has been modified to clarify this point. 12. Signatures, initials, etc, may not apply to all forms of evidence. "Dated" is more universal. 13. Corrective maintenance is included within PRC-005-2 only in that the initiation of resolution of maintenance-correctable issues (discovered during maintenance activities) is included. The SDT considers this inclusion to be appropriate and necessary as part of the maintenance program. 14. The portion of "Compliance" that referred to the Tables has been deleted. 15. The text to which you refer is part of the standard language for NERC Standards and reflects a general responsibility of the Compliance Enforcement Authority. The Compliance Enforcement Authority does not need to be indentified as an Applicable Entity. 16. If proper operation of an input or output is required such that the Protection System operate properly, it is "essential". "Verify operation …" means		

Organization	Yes or No	Question 5 Comment
to determine that the component functions properly. The typo has been corrected. **17. The text to which you refer has been deleted in consideration of your comment.** **18. The SDT disagrees; settings beyond those "essential for proper function of the relay" may be essential to proper functioning of the monitoring, etc, which is used to extend the maximum maintenance interval of the relay.** **19. The SDT has arranged the format of each of the cells within the Maintenance Activities column for the best clarity within each individual cell.** **20. The SDT believes that the 3-month interval is proper for unmonitored communications systems.** **21. Examples such as you suggest may violate the NERC Anti-Trust Guidelines by appearing to favor specific proprietary technologies. Some examples may be found in Section 15.5 of the Supplementary Reference Document.** **22. "Such as" refers to examples pertinent to various equipment technologies, and thus are equipment-dependent, as opposed to entity-selectable. Some examples may be found in Section 15.5 of the Supplementary Reference Document.** **23. The SDT believes that each individual trip coil needs to be verified as required within PRC-005-2.** **24. "Electromechanical" refers to any device which has moving parts that respond to electrical signals, such as lockout relays and auxiliary relays. This row in Table 1-5 has been modified.** **25. Yes. The verification of the entire control circuitry is performed according to the following row in the Table, on a less-frequent interval.** **26. The testing of the "remote trip scheme" seems best characterized as testing of a "Communications System". Accordingly, testing of the remote station control circuitry is an independent activity.**		
CenterPoint Energy	Yes	(a) CenterPoint Energy cannot support this proposed Standard. Any standard that requires a 35 page Supplementary Reference document and a 37 page FAQ - Practical Compliance and Implementation document, in addition to extensive tables in the Standard, is much too prescriptive and complex to be practically implemented. (b) 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 last 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 performance. (c) CenterPoint Energy is very concerned that a large increase in the amount of documentation will be required in order to demonstrate compliance - with no resulting reliability benefit. CenterPoint Energy

Organization	Yes or No	Question 5 Comment
		believes this Standard could actually result in decreasing system reliability, as the Standard proposes excessive maintenance requirements. The following is included in the Supplementary Reference document (page 8): "Excessive maintenance can actually decrease the reliability of the component or system. It is not unusual to cause failure of a component by removing it from service and restoring it." System reliability can be even further reduced by the number of transmission line and autotransformer outages required to perform maintenance. (d) The following is included in the FAQ - Practical Compliance and Implementation document: "PRC-005-2 assumes that thorough commission testing was performed prior to a protection system being placed in service. PRC-005-2 requires performance of maintenance activities that are deemed necessary to detect and correct plausible age and service related degradation of components such that a properly built and commission tested Protection System will continue to function as designed over its service life." CenterPoint Energy believes some proposed requirements, such as wire checking a relay panel, do not conform to this statement. CenterPoint Energy's experience has been that panel wiring does not degrade with age and service and that problems with panel wiring, after thorough commissioning, is not a systemic issue.
Response: Response: Thank you for your comments. **a. The SDT has decided to eliminate the FAQ and incorporate topics and discussion from the FAQ within the Supplementary Reference Document.** **b. FERC Order 633 directed that NERC establish maximum maintenance intervals. Additionally, the SDT is directed to develop a measurable, effective continent-wide standard. Entities may continue their current practices as long as those practices meet the minimum requirements of this standard.** **c. FERC Order 633 directed that NERC establish maximum maintenance intervals. The documentation required should not expand dramatically from the documentation currently required to demonstrate compliance. An entity may minimize hands-on maintenance by utilizing monitoring to extend the intervals.** **d. The standard does not require "wire-checking", but instead generically specifies "verification" – however an entity chooses to do so.**		
American Transmission Company	Yes	ATC recognizes the substantial efforts that the SDT has made on PRC-005 and appreciate the SDT's modifications to this Standard based on previous comments made. ATC looks forward to continuing to have a positive influence on this process via the comment process, ballots and interaction with the SDT. ATC was very close to an affirmative vote on this Standard prior to the unanticipated changes that appeared in this most recent posting. These changes introduce a significant negative impact from ATC's perspective. Therefore, ATC is recommending a negative ballot in the hope that our concerns regarding R 1.5 and R 4.2 and other clarifications will be included with the standard The two items within the proposed Standard that we take exception to are not directly related to implementing FERC Order 693. Rather, it is the overly

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>prescriptive nature with respect to the “how” as outlined in the proposed Standard that ATC takes exception... To improve and find the proposed Standard acceptable, ATC would like to see the following modifications:

1. Change the text to require the actuation of a single trip coil (row 1 of table 1.5). This would satisfy the intent to exercise the mechanism on a regular schedule, given that the mechanism binding is a much more likely source of a coil failure. The balance of trip coils could then be tested as part of routine breaker maintenance.

2. Eliminate the additional requirements introduced by the addition of R1.5 and the associated modifications to R4.2. The additional documentation required for the range of each element is typically incorporated into the pass/fail mechanism of the existing test equipment (which is reflective of the manufacturer recommendations) used to conduct these tests. Therefore, requiring the assembly of this additional documentation from each entity would:

a. Be duplicative and voluminous as it would require us to track thousands of additional data points due to the variability in element ranges by relay manufacturer, model number and vintage.

b. Not add to the reliability of the system as this function is already being performed on a collective basis.</td></tr>
<tr><td colspan="3">Response: Response: Thank you for your comments.

1. The SDT believes that each individual trip coil needs to be verified as required within PRC-005-2.

2. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.</td></tr>
<tr><td>Consumers Energy</td><td>Yes</td><td>1. Table 1-3 states, “are received by the protective relays”. Does this require that the inputs to each individual relay must be checked, or is it sufficient to verify that acceptable signals are received at the relay panel, etc?

2. Relative to Table 1-5, the activities will likely require that system components be removed from service to complete those activities. If the changes to the BES definition (per the FERC Order) causes system elements such as 138 kV connected distribution transformers to be considered as BES, these components can not be removed from service for maintenance without outaging customers. The standard must exempt these components from the activities of Table 1-5 if the activity would result in deenergizing customers.

3. For the component types addressed in Tables 1-3 and 1-5, the requirements may cause entities to identify components very differently than they are currently doing, and doing so may take several years to complete.</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
		The Implementation Plan for R1 and R4 is too aggressive in that it may not permit entities to complete the identification of discrete components and the associated maintenance and implement their program as currently proposed. We propose that the Implementation Plan specifically address the components in Table 1-3 and 1-5 with a minimum of 3 calendar years for R1 and 12 calendar years after that for R4. 4. As for the interval in Table 1-4 regarding the battery terminal connection resistance, we believe that an 18-month interval is excessively frequent for this activity, and suggest that it be moved to the 6-calendar-year interval. 5. In Table 1-4, we currently re-torque all of the battery terminal connections every 4-years, rather than measuring the terminal connection resistance to determine if the connections are sound. Disregarding the interval, would this activity satisfy the “verify the battery terminal connection resistance” activity?
Response: Response: Thank you for your comments. **1. The SDT intends that the voltage and current signals properly reach each individual relay, but there may be several methods of accomplishing this activity.** **2. This concern seems more properly to be one to be addressed during the activities to develop the new BES definition, rather than within PRC-005-2.** **3. The Implementation Plan for Requirement R1 has been modified from 6 months to 12 months. The Standard has also been modified (Requirement R1, Part 1.1) to not specifically require identification of all individual Protection System components. The Implementation Plan for Requirement R4 has been revised to add one year to all established dates.** **4. IEEE 450, 1188, 1106 all recommend this activity at a 12-month interval. Please see Section 15.4.1 of the Supplementary Reference Document for a discussion of this activity.** **5. Re-torqueing the battery terminals would not meet this requirement.**		
Southern Company Generation	Yes	1. Please consider retaining the definitions stated to be moved to the NERC Glossary - they would be valuable to entities in the standard. 2. On Page 5, Section 1.2, please consider changing “or a combination of these maintenance methods (per PRC-005-Attachment A).” to “or a combination of these two maintenance methods.” 3. On Page 5, Section 1.5: recommend deleting this section - the subjectivity of what is an acceptable value for component testing makes this requirement un-valuable. 4. On Page 5, Section 4.2, it is recommended that the requirement be the following: Either verify that the component performance is acceptable at the conclusion of the maintenance activities or initiate resolution of any identified maintenance correctable issue.

Organization	Yes or No	Question 5 Comment
		5. On Page 5, Measure M1, replace 1.5 with 1.4 (after eliminating Requirement 1.5) 6. On Page 6, Section 1.3, replace the existing Data Retention text with the following: The TO, GO, and DP shall each retain documentation for the longer of the these time periods: 1) the two most recent performances of each distinct maintenance activity for the Protection System component, or (2) all performances of each distinct maintenance activity for the Protection System component since the previous scheduled audit date. The Compliance Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent compliance records. 7. On Page 10, Section F, please correct the revision information for the documents listed. 8. On Pages 14 & 15, Table 1-4, move the bottom row to the next page so that it is easier to see that the maintenance activities are an “either/or” option. 9. On Page 17, Table 1-5, it seems that the 12 calendar year interval activities would automatically be included in the 6 calendar year activity for verifying the electrical operation of electromechanical trip and auxiliary devices. Is the 12 year requirement superfluous? 10. On Page 19, Attachment A, it is recommended to delete the footnote #1 since the definition is given already on Page 2.

Response: Response: Thank you for your comments.

1. **If the terms were placed in the Glossary of Terms, the SDT is concerned that some future SDT, in order to utilize these terms, may change them in a fashion inconsistent with the intended usage within PRC-005-2.**
2. **Requirement R1, Part 1.2 has been modified.**
3. **The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.**
4. **The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.**
5. **Measure M1 has been modified as you suggest.**
6. **The Data Retention section has been modified essentially as you suggest.**

Organization	Yes or No	Question 5 Comment
7. The Reference information has been corrected. **8. Table 1-4 has been revised.** **9. The 12-year interval activities are more extensive than the 6-year interval activities.** **10. Footnote #1 has been removed.**		
US Bureau of Reclamation	Yes	1. The concept of including definitions in this standard that are not a part of the Glossary of Terms will create a conflict with other standards that choose to use the term with a different meaning. This practice should be disallowed. If a definition is be introduced it should be added to the Glossary of Terms. This concept was not provided to industry for comment when the modifications to the Definition of Protection System were introduced. Additional related to this practice are included later on. 2. The Term "Protective Relays" is overly broad as it is not limited to those devices which are used to protect the BES. In the reference provided to the standard, the SDT defined "Protective Relays" as "These relays are defined as the devices that receive the input signal from the current and voltage sensing devices and are used to isolate a faulted portion of the BES. " The Definition for "Protective Relays" as well as the components associated with the them should be associated with the protection of the BES in the definition. 3. The Section 2.4 of the attached reference and the recent FERC NOPR are in conflict with the definition of "Protective Relays" which include lockout relays and transfer trip relays "The relays to which this standard applies are those relays that use measurements of voltage, current, frequency and/or phase angle and provide a trip output to trip coils, dc control circuitry or associated communications equipment. 4. This Draft 2: April3: November 17, 2010 Page 5 definition extends to IEEE device # 86 (lockout relay) and IEEE device # 94 (tripping or trip-free relay) as these devices are tripping relays that respond to the trip signal of the protective relay that processed the signals from the current and voltage sensing devices." The definition should be revised to reflect that is really intended. The SDT as created an implied definition by specifically defining DC circuits associated with the trip function of a "Protective Relay" but failing to specifically define voltage and current sensing circuits providing inputs to "Protective Relays". The team clearly intended the circuits to be included but the definition does not since it only refers the "voltage and current sensing devices". 5. Starting with the Definitions and continuing through the end of the document, terms that have been defined are not capitalized. This leaves it ambiguous as to whether the defined term is to be applied or it is a generic reference. Only defined terms "Protection System Maintenance Program" and "Protection System" are consistently capitalized. 6. Protection System Maintenance Program (PSMP) definition: The Restore bullet should be revised to read

Organization	Yes or No	Question 5 Comment
		as follows: "Return malfunctioning components to proper operation by repair or calibration during performance of the initial on-site activity."Add the following at the end of the PSMP definition: "NOTE: Repair or replacement of malfunctioning Components that require follow-up action fall outside of the PSMP, and are considered Maintenance Correctable Issues." 7. Protection System (modification) definition: The term "protective functions" that is used herein should be changed to "protective relay functions" or what is meant by the phrase should become a defined term, as it is being used as if it is a well known well defined, and agreed upon term. The first bullet text should be revised to read as follows: "Protective relays that monitor BES electrical quantities and respond when those quantities exceed established parameters," the last two bullets should be reversed in order and modified to read as follows: o control circuitry associated with protective relay functions through the trip coil(s) of the circuit breakers or other interrupting devices, and o station dc supply (including station batteries, battery chargers, and non-battery-based dc supply) associated with the preceding four bullets. 8. Statement between the Protection System (modification) definition and the Maintenance Correctable Issue definition; Is this a NERC accepted practice? There does not appear to be a location in the standard for defining terms. Having terms that are not contained in the "Glossary of Terms used in NERC Reliability Standards," and are outside of the terms of the standards, and yet are necessary to understand the terms of the Requirements is not acceptable. They would become similar to the reference documents, and could be changed without notice. 9. Maintenance Correctable Issue definition: The last sentence should be modified to read as follows: "Therefore this issue requires follow-up corrective action which is outside the scope of the Protection System Maintenance Program and the Standard PRC-005-2 defined Maximum Maintenance Intervals." The definition could also be easily clarified to read "Maintenance Correctable Issue - Failure of a component to operate within design parameters such that it cannot be restored to functional order by repair or calibration; therefore requires replacement." This ensures that any action to restore the equipment, short of replacement, is still considered maintenance. Otherwise ambiguity is introduced as what "maintenance" is. 10. Countable Event definition: An explanation should be made that this is a part of the technical justification for the ongoing use of a performance-based Protection System Maintenance Program for PRC-005. 11. Insert the phrase "Standard PRC-005-2" before the term "Tables 1-1..." 12. Applicability: 4.2. Facilities: 4.2.5.4 and 4.2.5.5: Delete these two parts of the applicability. Station service transformer protection systems are not designed to provide protection for the BES. Per PRC-005-2 Protection System Maintenance Draft Supplementary Reference, Nov. 17 2010, Section 2.3 - Applicability of New Protection System Maintenance Standards: "The BES purpose is to transfer bulk power. The applicability language has been changed from the original PRC-005: "...affecting the reliability of the Bulk

Organization	Yes or No	Question 5 Comment
		Electric System (BES)...”To the present language:”... and that are applied on, or are designed to provide protection for the BES.”The drafting team intends that this Standard will not apply to “merely possible” parallel paths, (sub-transmission and distribution circuits), but rather the standard applies to any Protection System that is designed to detect a fault on the BES and take action in response to that fault.”Station Service transformer protection is designed to detect a fault on equipment internal to a power plant and not directly related to the BES. In addition, many Station Service protection ensures fail over to a second source in case of a problem. Thus station service transformer protection system is a power plant reliability issue and not a BES reliability issue. As such station service transformer protection should not be included in PRC 005 2.In addition; the SDT appears to have targeted generation station service without regard to transmission systems. If generating station service transformers are that important, then why are substation/switchyard station service transformers not also important? 13. B. Requirements Should the sub requirements have the "R" prefix? 14. R4.Change the phrase "... PSMP, including identification of the resolution of all ..." to read "...PSMP including identification, but not the resolution, of all ...". 15. General comment PRC005-2 is very specific in listing the maximum maintenance interval but is still very vague in listing the specific components to test. Suggest adding the following to the standard. a. A sample list of devices or systems that must be verified in a generator to meet the requirements of this Maintenance Standard: b. Examples of typical devices and relay systems that respond to electrical quantities and may directly trip the generator, or trip through a lockout relay may include but are not necessarily limited to: Fault protective functions, including distance functions, voltage-restrained overcurrent functions, or voltage-controlled overcurrent functions Loss-of-field relays Volts-per-hertz relays Negative sequence overcurrent relays Over voltage and under voltage protection relays Stator-ground relays Communications-based protection systems such as transfer-trip systems Generator differential relays

Organization	Yes or No	Question 5 Comment
		Reverse power relays Frequency relays Out-of-step relays Inadvertent energization protection Breaker failure protection o lockout or tripping relays c. For generator step up transformers, operation of any the following associated protective relays frequently would result in a trip of the generating unit and, as such, would be included in the program: Transformer differential relays o Neutral overcurrent relay Phase overcurrent relays 16. In the Lower, Moderate and Severe VSL descriptions, in addition to not being capitalized, the defined term Maintenance Correctable Issues should not be hyphenated. 17. In Attachment A Section 2 Page 51 should be modified as follows: 2. Maintain the components in each segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5 until results of maintenance activities for the segment are available for a minimum of either 30 individual components of the segment or a significant statistical population of the individual components of a segment." Without the modification the requirement unfairly target smaller entities. This will allow smaller entities to determine adjust its time based intervals if its experience with an appropriate number of components supports it. In Attachment A Section 5 Page 51 should be modified as follows: 5. Determine the maximum allowable maintenance interval for each segment such that the segment experiences countable events on no more than 4% of the components within the segment, for the greater of either the last 30 components maintained or a significant statistical population of the individual components of a segment maintained in the previous year. Without the modification the requirement unfairly target smaller entities. This will allow smaller entities to determine adjust its time based intervals if its experience with an appropriate number components supports it. 18. In Attachment A Section 5 Page 52 should be modified as follows: 5. Using the prior year's data, determine the maximum allowable maintenance interval for each segment such that the segment experiences countable events on no more than 4% of the components within the segment, for the greater of either the last 30 components maintained or a significant statistical population

Organization	Yes or No	Question 5 Comment
		of the individual components of a segment components maintained in the previous year. Without the modification the requirement unfairly target smaller entities. This will allow smaller entities to determine adjust its time based intervals if its experience with an appropriate number of components supports it.

Response: Thank you for your comments.

1. **If the terms were placed in the Glossary of Terms, the SDT is concerned that some future SDT, in order to utilize these terms, may change them in a fashion inconsistent with the intended usage within PRC-005-2.**
2. **"Protective relay" is defined by IEEE, and the SDT sees no need to either change the definition or to repeat the definition within PRC-005. Further, the applicability of generically-described protective relays is defined by the Applicability clause of PRC-005-2.**
3. **The issues raised by the FERC NOPR will be addressed as part of the response to the NOPR (and ultimately the Order). The extension to auxiliary and lockout relays is not part of the protective relay (addressed within Table 1-1), but instead as part of the control circuitry (Table 1-5).**
4. **The extension to auxiliary and lockout relays is not part of the protective relay (addressed within Table 1-1), but instead as part of the control circuitry (Table 1-5).**
5. **Definitions from the NERC Glossary of Terms (or those intended for the Glossary) are consistently capitalized (Protection System and Protection System Maintenance Program fall within this category). As for terms defined only for use within this standard, these terms are NOT capitalized, since they are not in the Glossary of Terms.**
6. **The "restore" portion of PSMP specifically addresses returning malfunctioning components to proper operation. The requirements regarding maintenance correctable issues are further addressed within that definition (for use only within PRC-005-2).**
7. **The SDT is currently not planning on further modifying the most recent NERC BOT-approved definition of Protection System.**
8. **If the terms were placed in the Glossary of Terms, the SDT is concerned that some future SDT, in order to utilize these terms, may change them in a fashion inconsistent with the intended usage within PRC-005-2.**
9. **Identifying problems, but not fixing them, does not constitute an effective program. In deference to the time that may be necessary to repair/replace defective components, the SDT has decided to require only initiation of resolution of maintenance correctable issues, not to demonstrate completion of them.**
10. **Since this term is used only in Attachment A, it seems unnecessary to provide the explanation requested.**
11. **The SDT has elected not to change the reference to the Tables throughout the standard.**
12. **Applicability 4.2.5.5 has been removed. Generator-connected station service transformers (4.2.5.4) are essential to the continuing operation of the generating plant; therefore, protection on these system components is included within PRC-005-2 if the generation plant is a BES facility.**
13. **The current style guide for NERC Standards does not preface the subparts with an "R".**
14. **Identifying problems, but not fixing them, does not constitute an effective program. In deference to the time that may be necessary to**

Organization	Yes or No	Question 5 Comment
repair/replace defective components, the SDT has decided to require only initiation of resolution of maintenance correctable issues, not to demonstrate completion of them. **15. The various specific components you suggest are addressed within the Facilities portion of the Applicability 4.2.5, as well as other components that satisfy the attributes within 4.2.5. These examples are in the Supplementary Reference Document (Section 8.1.3).** **16. Within the VSLs, the hyphenated term has been corrected.** **17. The SDT has determined that 30 individual components is the minimum acceptable statistically-significant population for use to establish performance-based intervals. Multiple entities may aggregate component populations to establish this component population, provided that the programs are sufficiently similar to make the aggregation valid. See Supplementary Reference Document Section 9 for a discussion.** **18. The SDT has determined that 30 individual components is the minimum acceptable statistically-significant population for use to establish performance-based intervals. Multiple entities may aggregate component populations to establish this component population, provided that the programs are sufficiently similar to make the aggregation valid. See Supplementary Reference Document Section 9 for a discussion.**		
Alliant Energy	Yes	1. In the Purpose statement delete “affecting” and replace it with “protecting”. The purpose of the standard deals with systems that protect the BES. 2. In sections R1 and R4.2.1 delete “applied on” as unneeded and potentially confusing. The goal is to cover Protection Systems designed to protect the BES. 3. Alliant Energy believes that Article 1.4 needs to be deleted from the standard. It is redundant and serves no purpose. 4. Alliant Energy believes that Article 1.5 needs to be deleted from the standard. There is a major concern on what an “acceptable parameter” is and how it would be interpreted by the Regional Entities. 5. Section 4.2 Applicable Facilities: We are concerned with this paragraph being interpreted differently by the various regions and thereby causing a large increase in scope for Distribution Provider protection systems beyond the reach of UFLS or UVLS.4.2.1 Protection Systems applied on, or designed to provide protection for, the BES. The description is vague and open for different interpretations for what is “applied on” or “designed to provide protection”. According to the November 17, 2010 Draft Supplementary Reference page 4, the Standard will not apply to sub-transmission and distribution circuits, but will apply to any Protection System that is designed to detect a fault on the BES and take action in response to the fault. The Standard Drafting Team does not feel that Protection Systems designed to protect distribution substation equipment are included in the scope of this standard; however, this will be impacted by the Regional Entity interpretations of ‘protecting” the BES. Most distribution protection systems will not react to a fault on the BES, but are caught up in the interpretation due to tripping a breaker(s) on the BES. We request clarification that the examples listed below do not constitute components of a BES Protection

Organization	Yes or No	Question 5 Comment
		System: 1. Older distribution substations that lack a transformer high side interrupting device and therefore trip a transmission breaker or a portion of the transmission system or bus, or 2. Newer distribution substations that contain a transformer high side interrupting device but also incorporate breaker failure protection that will trip a transmission breaker or a portion of the transmission system or bus. 6. Since distribution provider systems are typically radial and do not contain the level of redundancy of transmission or generation protection systems, it is not cheap, safe, maintaining BES reliability, or easy to coordinate companies to test these protection systems to the level of PRC-005-2 draft recommendations. 7. Section F Supplementary Reference Documents: The references listed in this section refer to 2009 dates and do not match with the 2010 reference documents supplied for comment. 8. Table 1-4 Component Type Station dc Supply: a. "Any dc supply for a UFLS or UVLS system" - This should not have the same testing interval as control circuits, but should have a maximum maintenance period as other dc supplies do. b. Replace the words "perform as designed" on page 14 of Table 1-4 with "operate within defined tolerances."Table 1-5 Component Type Control Circuitry: c. This table allows for unmonitored trip coils for UFLS or UVLS breakers to have "no periodic maintenance". The PRC-005-2 Supplementary Frequently Asked Question #7B and #7C give excellent reasoning for not requiring maintenance on the trip coil component due to the larger number of failures that would be required to have any substantial impact to the BES as well as the statement that distribution breakers are operated often on just fault clearing duty already. We believe that the unmonitored control circuitry has the same level of minimal BES impact and is also being tested each time the distribution breaker undergoes fault clearing duty. With this logic, we do not see why there would be different maintenance requirements for these two components. d. Alliant Energy is concerned that the addition of mandatory 86 and 94 auxiliary lockout relays (Electromechanical trip or Auxiliary devices) will force entire bus outages that will compromise the BES reliability more by forcing utilities across the US to unnecessarily take multiple non-faulted BES elements out of service. Such testing is also likely to introduce human error that will cause outages such as items outlined in the NERC lessons learned" and therefore such testing will result in more outages than actual failures. An equivalent non-destructive test needs to be identified to allow entities to sufficiently trace and test trip paths without taking multiple substation line outages to physically test a lockout or breaker failure scheme.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comments. **1. The "Purpose" is defined by the SAR.** **2. Requirement R1 and Requirement R4, Part 4.2.1 have been modified as you suggested.** **3. The SDT instead elected to remove Requirement R2.** **4. The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.** **5. Applicability 4.2.1 has been revised to remove 'applied on". The SDT believes that this addresses your concern. Applicability 4.2.2 and 4.2.3, respectively, address UFLS and UVLS specifically, and are not related to 4.2.1. The Supplementary Reference Document has been revised to clarify. PRC-005-2 would appear to apply to both cited examples.** **6. This is properly a concern to be addressed within the current SDT that is developing a revised definition of Bulk Electric System.** **7. The date in Clause F of the standard related to the Supplementary Reference Document has been revised.** **8. a. The SDT disagrees. Station dc supply for UFLS/UFLS only is limited in its impact, and the SDT believes that using the same intervals as for the related control circuits.** **b. "Tolerances" does not fully describe the parameters for maintenance of station dc supply; "perform as designed" is far more inclusive.** **c. The SDT intends that tripping of the interrupting device for UFLS/UVLS is not required, but that the other portions of the dc control circuitry still shall be maintained. See Section 15.3 of the Supplementary Reference Document.** **d. 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**		
LCRA Transmission Services Corporation	No	
MidAmerican Energy	Yes	1. MidAmerican remains concerned that including requirements for testing of electromechanical trip or auxiliary devices (Table 1-5 Row 3) will in some cases require entire bus outages that will compromise the BES reliability due to the need for entities across the US to take multiple BES elements out of service during the testing. If this requirement is retained additional time should be included in the implementation plan to allow for system modifications, such as the installation of relay test switches, to potentially allow

Organization	Yes or No	Question 5 Comment
		for this testing while minimizing testing outages. 2. Clarify that in the definition of Component Type that Transmission Owners are allowed the latitude to designate their own definitions for each of the Component Types, not just control circuits. 3. In the implementation schedule time periods are provided within which compliance deadlines and percentages of compliance are given. The following clarifications are recommended: 1. In calculating percentage of compliance for purposes of demonstrating progress on the implementation plan the percentages are calculated based on the total population of the protection system components that an entity has that fit the component category and allowable interval. 2. To obtain compliance with the percentage completion requirements of the implementation schedule an entity needs to have completed at least one prescribed maintenance activity of that component type and interval. 4. In the purpose statement delete “affecting” and replace it with “protecting”. The purpose of the standard deals with systems that protect the BES. 5. In sections R1 and R4.2.1 delete “applied on or” as unneeded and potentially confusing. The goal is to cover protection systems designed to protect. 6. Clarify the meaning of “state of charge” on page 14 in Table 1-4. 7. In Table 1-4 Component Type Station dc Supply, “Any dc supply for a UFLS or UVLS system” should have the same maximum maintenance period as other dc supplies. 8. Table 1-5 Component Type Control Circuitry, the table allows for unmonitored trip coils for UFLS or UVLS breakers to have “no periodic maintenance”. The PRC-005-2 Supplementary Frequently Asked Question #7B and #7C give excellent reasoning for not requiring maintenance on the trip coil component due to the larger number of failures that would be required to have any substantial impact to the BES as well as the statement that distribution breakers are operated often on just fault clearing duty already. We believe that the unmonitored control circuitry has the same level of minimal BES impact and is also being tested each time the distribution breaker undergoes fault clearing duty. With this logic, we do not see why there would be different maintenance requirements for these two components.

Response: Thank you for your comments.

1. **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.**

Organization	Yes or No	Question 5 Comment
2. For components other than control circuitry, the SDT believes that identification of the components as established within the draft Standard is appropriate. There is no latitude regarding component types. **3. The SDT believes that the Implementation Plan clearly agrees with your interpretation, and no clarification seems necessary.** **4. The "Purpose" is defined by the SAR.** **5. Requirement R1 and Requirement R4, Part 4.2.1 have been modified as you suggested.** **6. Table 1-4 has been revised to remove "state of charge" from the activities.** **7. The SDT disagrees. Station dc supply for UFLS/UVLS only is limited in its impact, and the SDT believes that using the same intervals as for the related control circuits is appropriate.** **8. For the control circuitry of UFLS/UVLS, the relatively frequent breaker operations may not be reflective of proper functioning for UFLS/UVLS function. Therefore, minimal maintenance activities are necessary for these cases.**		
Ameren	Yes	(1) We believe that R1.5 and R4.2 "Calibration tolerances or other equivalent parameters" requirements should be removed. Neither the Supplement nor the FAQ address the expectation for them. While we agree that tolerances are needed and used, they need not be specified as part of this standard. (2) The Data retention is too onerous (a) For those components with numerous cycles between on-site audits, retaining and providing evidence of the two most recent distinct maintenance performances and the date of the others should be sufficient. Additionally, we are subject to self-certification, spot audits and/or inquiries at any time between on-site audits as well. (b) 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. (3) Definition of the BES perimeter should be included in accordance with Project 2009-17 Interpretation. (a)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. (4)System-connected station service transformers (4.2.5.5) should be omitted, because (a) 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. (b) system-connected station service transformers in the same table as well as from table-to-table can be overwhelming. This would help keep Regional Entities and System Owners from

Organization	Yes or No	Question 5 Comment
		making errors. (5) Retention of maintenance records for replaced equipment should be omitted. FAQ II 2B final sentence states that documentation for replaced equipment must be retained to prove the interval of its maintenance. We disagree with 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. (6) Battery inspection every 4 months is sufficient. 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. (7) PSMP Implement Date should commence at the beginning of a Calendar year. This is the most practical way to transition assets from our existing PRC-005-1 plans. (8) Please clarify the meaning of "state of charge" for batteries. Does this mean specific gravity testing or what? (9) Please clarify that instrument transformer itself is excluded. Please clarify that the instrument transformer itself is excluded. The standard indicates that only voltage and current signals need to be verified in Table 1-3, but the recently approved Protection System definition wording can be mis-interpreted to mean they are included. FAQ 11.3.A is helpful.

Response: Thank you for your comments.

1. **The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.**
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 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. This seems to be consistent with the current practices of several Regional Entities.**
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**

Organization	Yes or No	Question 5 Comment
make associated changes. **4. In response to many comments, including yours, the SDT has removed 4.2.5.5 from the Applicability of the standard.** **5. The SDT has decided to eliminate the FAQ and incorporate topics and discussion from the FAQ within the Supplementary Reference Document. Your comments will be considered within that activity. The SDT believes that entities should retain the evidence necessary to demonstrate compliance for the entire period reflected within Data Retention, and the discussion within the Supplementary Reference Document suggests that this includes records of retired equipment.** **6. The SDT believes that the 3-month interval specified in the Standard is appropriate.** **7. The guidance provided to the SDT provides that the implementation dates should begin on the first day of a calendar quarter.** **8. Table 1-4 has been revised to remove "state of charge" from the activities.** **9. The SDT intends that the instrument transformer and associated circuitry be verified to be functional, but believes that customary apparatus maintenance (dielectric, infrared, etc) are not relevant to PRC-005-2. The SDT has decided to eliminate the FAQ and incorporate topics and discussion from the FAQ within the Supplementary Reference Document.**		
Xcel Energy	Yes	1. Requirement R1.4 in part requires that the entity's PSMP includes all monitoring attributes to include those specified in Tables 1-1 through 1-5. Requirement R2 requires that entities that use maintenance intervals for monitored Protection Systems shall verify those components possess the monitoring attributes identified in Tables 1-1 through 1-5. The intent and differences between these 2 requirements is unclear. If an entity does not choose to use monitored intervals, it makes no sense to require them to include the monitoring attributes identified in Tables 1-1 through 1-5 within their PSMP. Furthermore if an entity fails to meet requirement R1.4 for including identified monitoring attributes in its program, it will by default also have violated R2. There seems the possibility of double jeopardy between R1.4 and R2. The intent of R2 is fairly obvious but the intent of including monitoring attributes in R1.4 is not evident. Please provide a discussion within the FAQ to better explain the differences between these two requirements as they relate to monitoring attributes. 2. As written, requirement R1.5 and application of R1.5 acceptance criteria via requirement R4.2 would open entities up to vague interpretations by compliance personnel as to what constitutes adequate acceptance criteria – particularly in the area of subjective inspection results – e.g., battery cell visual inspections. We recommend that R1.5 be re-stated to clarify that acceptance criteria need only be provided for numerically measurable parameters. FAQs should be written to better explain the intent of R1.5 and to provide examples of acceptance criteria and to hopefully drive consistency amongst compliance personnel interpretation of acceptance criteria requirements. Consideration should be given to identifying which maintenance requirements in the Tables would generate quantifiable and measurable test results for which acceptance

Organization	Yes or No	Question 5 Comment
		criteria would be expected.

Response: Thank you for your comments.

1. **The SDT had concluded that Requirement R2 is redundant with Requirement R1, Part 1.4, and has deleted R2 (together with the associated Measure and VSL).**
2. **The SDT has determined that the fundamental concerns of Requirement R1, Part 1.5 and the associated changes are addressed within the PSMP definition, and that Requirement R1, Part 1.5 is not necessary; therefore, it has been removed. Requirement R4 has also been re-drafted to address various related concerns noted within comments. The associated VSL has also been revised. Please see Supplementary Reference Document, Section 8 for a discussion of this.**

END OF REPORT