NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot — Protection System Maintenance and Testing (Project 2007-17)
Date of Initial Ballot: December 10 – 20, 2010

Summary Consideration: Many commenters opposed R1 part 1.5 and the associated text, and the SDT responded by removing this text. Most of these comments were duplicates of those submitted in response to the formal comment period; the SDT responses are duplicated as well. Please see the Summary Consideration for each of the posted questions within the Consideration of Comments.

If you feel that the drafting team overlooked your comments, 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, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Rodney Phillips	Allegheny Power	1	Negative	Allegheny Power applauds the hard work that the Standards Draft Team has exhibited in producing a clear and enforceable standard that will increase the reliability of the Bulk Electric System. However, the addition of requirement 1.5 is such a significant change in scope from the last draft that a further review of the potential impact and any implementation concerns is required by AP and the industry in general before we can consider voting in-favor of this standard.
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.**				
Kirit S. Shah	Ameren Services	1	Negative	(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)
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.**				
Paul B. Johnson	American Electric Power	1	Negative	Restructured Tables: 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. Also, unmonitored control circuitry is capitalized in row 4 such that it infers a defined term. 2) 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

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

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				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. 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. VSLs, VRFs and Time Horizons: 3) The VSL table should be revised to remove the reference to the Standard Requirement 1.5 in the R1 "High" VSL. 4) All four levels of the VSL for R2 make reference to a "condition-based PSMP." However, nowhere 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. 5) 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. FAQ and Supplementary Reference: 6) 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: a) Section 5 of the Supplementary Reference, refers to "condition-based" maintenance programs. However, nowhere 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.

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				b) Section 15.7, page 26, appears to have a typographical error "…can all be used as the primary action is the maintenance activity…" c) 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. 7) "Frequently-Asked Questions": 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: a) The section "Terms Used in PRC-005-2" is blank and should be removed as it adds no value. b) Section I.1 and Section IV.3.G reference "condition-based" maintenance programs. However, nowhere 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. c) 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…". 8) General: a) 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. b) 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 a knowledge of material in the Supplementary

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				Reference or FAQ. c) “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.

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 circuitry. The capitalized term has been corrected.

2. Table 1-4 has been modified in consideration of your comments.

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.

4. The SDT concluded that Requirement R2 is redundant with R1, Part 1.4, and has deleted R2 (together with the associated Measure and VSL).

5. If the indicated monitoring attributes are present, no “hands-on” periodic maintenance is required, as the monitoring of the component is providing a continuing indication of its functionality.

6. The discussion within the Supplementary Reference and FAQ are informative, not normative, and thus do not belong as part of the standard.

A. The Supplemental Reference Document discusses condition-based maintenance in a conceptual manner, as a generally-recognized term. The SDT did make some changes within the Supplemental Reference document to clarify the manner in which condition-based maintenance is discussed.

B. This clause has been corrected.

C. A higher-quality version of Figure 2 has been substituted.

7. The discussion within the Supplementary Reference and FAQ are informative, not normative, and thus do not belong as part of the standard.

a) 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.
b) 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.
c) The SDT decided to eliminate the FAQ document and incorporate the FAQ’s contents into the Supplementary Reference

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Document as appropriate. The SDT considered your comments during this activity. **8. 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 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.** **C) "Protective relay" is defined by IEEE, and the SDT sees no need to either change the definition or to repeat the definition with PRC-005. Further, the applicability of generically-described protective relays is defined by the Applicability clause of PRC-005-2.**				
Jason Shaver	American Transmission Company, LLC	1	Negative	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.
1. **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.**				
John Bussman	Associated Electric Cooperative, Inc.	1	Negative	AECI want to thanks the team for the efforts being put forth by the drafting team. The table is much easier to follow and less confusing. AECI is voting negative because of the battery inspection intervals. 1. We have commented before about the 3 months being excessive and think it should be annually. However, with that being stated if you are going to use three months as the interval then that means inspections will have to be scheduled every 2 months to ensure the inspections happen every 3 months. Therefore AECI request that the battery inspection schedule be extended to every 4 months and then entities can schedule inspections to be performed every 3 months to ensure that the inspections are completed every 4 months.

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				2. The same comment applies the the unmonitored communication circuits. Change the time interval to 4 months. Then scheduling can be every 3 months instead of every 2 months. 3. When you go to Table 1-4 there is confusion with the the DC for a UFLS or UVLS system. For the interval it states "When control circuits are verified" Then I go to Table 1-5 the second line that discusses trip coils for UFLS and UVLS the interval states "No periodic maintenance specified" Is this what was intended?
Response: **Thank you for your comments.** **1. The SDT believes that the 3-month interval is proper.** **2. The SDT believes that the 3-month interval is proper for unmonitored communications systems.** **3. 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**				
Joseph S. Stonecipher	Beaches Energy Services	1	Negative	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 we see as a problem 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, 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 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 regionsl 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 line breakers 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 nill. 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

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				trips a BES Facility." 3. Applicability, 4.2. - does not reflect the interpretation of Project 2009-10 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.
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 related 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. However, the SDT has made changes to Applicability 4.2.1. in consideration of your comment. 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 the gap.				
Donald S. Watkins	Bonneville Power Administration	1	Negative	Please see BPA's formal comments submitted on 12/16/10. Our concerns have not been adequately addressed.
Response: Thank you for your comments. Please see our responses to your comments from the formal comment period.				
Paul Rocha	CenterPoint Energy	1	Negative	1) 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 is much too prescriptive and complex. 2) 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 believes this Standard could actually result in decreasing system reliability, as the Standard proposes excessive maintenance requirements. The following is included in the

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				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. 3) In addition, 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: **Thank you for your comments.** **1. The SDT decided to eliminate the FAQ document and incorporate the FAQ's contents into the Supplementary Reference Document as appropriate.** **2. FERC Order 693 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.** **3. The standard does not require "wire-checking," but instead generically specifies "verification" – however an entity chooses to do so.**				
Jack Stamper	Clark Public Utilities	1	Negative	My no vote reflects my concern regarding the testing of Station DC Supply (Table 1-4) and Alarming Paths (Table 2). The SDT has provided much clarity to this standard in the testing requirements for relays, communication systems, voltage and current sensing devices, and control circuitry. 1. Table 1-4 is still confusing. There are five separate categories of unmonitored Station DC Supply testing requirements. It is unclear whether these categories are to be combined or if they are mutually exclusive. The first category applies to "Any unmonitored station dc supply not having the monitoring attributes of a category below" and appears to be a set of inspection and verification

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				requirements that are generally applicable to all unmonitored Station DC Supplies. The next four categories are applicable to Station DC Supply with specified types of batteries. If a station has unmonitored vented lead-acid batteries, are the batteries ONLY subject to the testing requirements for VLA batteries? OR would these batteries ALSO be subject to the requirements of the first category? It appears that the intent is for all Station DC Supply not having any monitoring attributes to be tested and maintained in accordance with the first category as well as the second through fifth category that is applicable. If this is the case, the SDT should consider revising the Component Attributes in Table 1-4 for the first category of Unmonitored Station DC Supplies to the following: Any unmonitored station dc supply not having the monitoring attributes of a category below. (excluding UFLS and UVLS). Station DC Supply devices applicable under these Table 1-4 general requirements will have additional testing requirements as described below for non-battery systems, VRLA battery systems, VLA battery systems, and Ni-Cad battery systems. 2. Do monitored batteries need to have all of the monitoring attributes listed or does having some of the monitoring attributes qualify a device as "Monitored?" The frequently asked questions examples on pages 30 - 32 seem to indicate that if only some of the items are monitored, the Station DC Supply is considered “Monitored” as long as other items are tested or verified. If this is the case, the SDT should consider revising the Component Attributes in Table 1-4 for the first category of Monitored Station DC Supplies to the following: Monitored Station dc supply (excluding UFLS and UVLS) with: Monitor and alarm for variations from defined levels (See Table 2): o Station dc supply voltage (voltage of battery charger) o State of charge of the individual battery cell/units o Battery continuity of station battery o Cell-to-cell (if available) and battery terminal resistance. Monitored Station dc supply will have one or more of the above listed conditions monitored or alarmed with the remainder of the conditions subject to inspection and verification activities. 3. In Table 2, the first Component Attribute for Alarm Paths contains the requirement that “Alarms are automatically reported within 24 hours of DETECTION to a location where corrective action can be taken.” I believe the term “automatically” should be removed. This term implies an automated process without human intervention. However, many facilities (i.e. generator

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				protection devices or manned substations) have protective devices that while not being subject to continuous monitoring, are visually inspected in daily or twice daily inspections. If protection devices have internal self-diagnostics that provide an alarm (i.e. failure indication on faceplate, relay interrogation, or LED failure indicator) and these devices are inspected one or more times per day, failures or malfunctions would be reported within the 24 hour DETECTION time. This appears to be within the intent of the standard which is to make sure that failed protective devices do not remain in failure longer than 24 hours without notification to a location where corrective action can be taken.
Response: **Thank you for your comments.** **1. Table 1-4 has been modified in consideration of your comments.** **2. Table 1-4 has been modified in consideration of your comments, and has been revised to remove "state of charge".** **3. "Automatically" has been removed from Table 2 in consideration of your comment.**				
Danny McDaniel	Cleco Power LLC	1	Negative	Cleco applies its' UFLS on the distribution grid with each UF relay individually tripping a relatively low value of load thru breakers and reclosers. Since our program is implemented via a large number of individual components, breakers, reclosers, and individual batteries, the failure of any one component will have a minimal impact on the effectiveness of the overall UFLS program within our region. Therefore, the verification of sensing devices, dc supply voltages, and the paths of the control circuit and trip circuits on the UFLS systems implemented on the distribution grid is unnecessary.
Response: **Thank you for your comments. The SDT disagrees; the sensing devices, control circuitry and dc supply related to UFLS has an effect on the performance of the UFLS. The SDT has, however, respected the overall impact on the control circuitry of individual UFLS on BES reliability by requiring that UFLS be subjected to a subset of the overall sensing devices, control circuitry and dc supply maintenance activities.**				
Paul Morland	Colorado Springs Utilities	1	Negative	CSU offers the following comments: 1. The document refers to the "BES" or "Bulk Electrical System" yet we have been unable to get a clear definition as to what that is. 2. 1.5 Because some calibration tolerances, such as communications schemes, change with the weather conditions, establishing tolerances could be difficult if the weather conditions are not factored into the tables. 3. 4.2.5.4 There needs to be a clear definition for "Station Service Transformers". 4. The reference to testing tolerances implies that test equipment must be calibrated to some standard, which this document does not discuss, and leaves a very wide interpretation for what this standard is, or the required calibration is required. 5. Table 1-3 Voltage and current devices may be connected to a meter and compared to a reference source to verify proper operation of the CT or PT. This seems to be at error in thinking that only microprocessor relays can be

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				used to verify CT or PT's. Also in many PT's there is more than one winding and tap, or which this standard seems to imply that only one needs to be monitored to verify the correct function of all of the windings and taps. If I were to follow this logic, I only need to monitor one winding of a dual core CT.
Response: Thank you for your comments. 1. Bulk Electric System is defined by NERC, and further defined by the Regional Entities. Please refer to these definitions. 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. Station Service transformer provide power to the auxiliary busses of generating plants. Some alternative names for these devices are "unit auxiliary transformers", "station auxiliary transformers", The SDT believes that these devices are commonly understood throughout industry and therefore require no definition. 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. Table 1-3 does not prescribe how the voltage and current sensing device inputs to the protective relays shall be verified, just that they be verified according to the established intervals. Please see Section 15.2 of the Supplementary Reference Document for a discussion on this topic.				
Christopher L de Graffenried	Consolidated Edison Co. of New York	1	Negative	PRC-005 Initial Ballot Comments: 1. The Tables - 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. 2. Other Comments - 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. 3. Why are "Relays that respond to non-electrical inputs or impulses (such

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				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. 4. 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. 5. 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? 6. 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. 7. 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. 8. A control circuit is not a component, it is made up of components. 9. 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

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				enforcement personnel. 10. 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. 11. 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. 12. 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.

Response: Thank you for your comments.

1. The SDT believes that the table headings are appropriate as reflected in the draft standard.

2. 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 to be prescribed. If an entities’ experience is that components require less-frequent maintenance, a performance-based program in accordance with Requirement R3 and Attachment A is an option.

3. 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.

4. 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 can maintain these devices more frequently if you desire.

5. With respect to dc supply associated only with communication 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 decided to

Voter	Entity	Segment	Vote	Comment
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. **6. 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 used here. They are defined only for clarify within this standard. The SDT will confirm with NERC staff that this approach is acceptable.** **7. 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.** **8. For purposes of this standard, the control circuit IS defined as one component type..** **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. 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.** **11. Table 1-4 has been further modified for clarity.** **12. In response to many comments, including yours, the SDT has removed 4.2.5.5 from the Applicability of the standard.**				
Robert W. Roddy	Dairyland Power Coop.	1	Negative	In Table 1-5 it is unclear which devices the Maximum Maintenance Intervals would be held to, such as trip coils of circuit breakers and coils of electromechanical trip or auxiliary relays whose continuity and energization are monitored and alarmed.
Response: Thank you for your comments. Trip coils of circuit breakers have a 6-year interval for physical operation. Coils of lockout and auxiliary relays also have a 6-year interval for physical operation. Control circuitry whose continuity and energization or ability to operate are monitored and alarmed require no hands-on maintenance.				
John K Loftis	Dominion Virginia Power	1	Negative	Dominion is opposed to this version because Requirement R1.5 is overly prescriptive, requiring an extraordinary level of documentation, with little anticipated improvement in 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.				

Voter	Entity	Segment	Vote	Comment
George R. Bartlett	Entergy Corporation	1	Negative	The restructured tables are generally much clearer and the SDT is to be commended on their efforts. 1. 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 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? 2. 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? 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 for a component type besides protective relays. Adding Requirement 1.5 is a significant revision and raises questions as to how broadly an accuracy or equivalent parameter requirement and associated

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td></td><td>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.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.
1. The Maximum Maintenance Interval column entry in Table 2 has been revised to state, "When alarm producing Protection System component is verified" to clarify 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.</td></tr>
<tr><td>Robert Martinko</td><td>FirstEnergy Energy Delivery</td><td>1</td><td>Negative</td><td>Please see FirstEnergy's comments submitted separately through the comment period posting.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.
Please see our responses to your comments from the formal comment period.</td></tr>
<tr><td>Gordon Pietsch</td><td>Great River Energy</td><td>1</td><td>Negative</td><td>1. We believe that requiring an entity to identify calibration tolerances in their PSMP does not add a material benefit and does not contribute to increased reliability. In addition we believe that R1.5 should be rewritten to state that a Relay test report should show when a Relay fell out of tolerance. R4.2 should be rewritten to state that if a test report does show that a Relay was out of tolerance it should be required to show that resolution was initiated.
2. The Activities section of Table 1.3 should be revised to include that the signals do not have to come from energized voltage or current sensing devices. The current or voltage signals can come from a test set. Note: It may be difficult to energize CTs or VTs for large capacitor banks, reactors, or generating units.</td></tr>
<tr><td colspan="5">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.</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
2. Table 1-3 has been modified in consideration of your comments.				
Ajay Garg	Hydro One Networks, Inc.	1	Negative	Hydro One is casting a negative vote with the following comments: 1. The added requirement R1, Part 1.5 is vague and needs clarification. It is not clear what “Identify calibration tolerances or other equivalent parameters” means and as written will be subject to different interpretations by entities and compliance enforcement personnel. The addition of this new part of Requirement R1 that requires the Owners to “identify calibration tolerances or other equivalent parameters for each Protection System component type” is onerous and contributes little to the reliability of the BES. 2. Changes introduced to the Implementation Plan since the last posting are not consistent with respect to jurisdictions where no regulatory approval is required. The previously posted implementation for Requirement R1 required entities to be 100% compliant on the first day of the first calendar quarter three months following applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter six months following Board of Trustees adoption. The amended implementation plan changed the three-month time to twelve months in jurisdictions with regulatory approval required but left the same six-month time for the others. For consistency, the six months timeframe should be changed to fifteen 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 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 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.				
Michael Moltane	International Transmission Company Holdings Corp	1	Negative	1. ITC votes "Negative" for the following reasons: Our negative ballot is based on our objection to the 6 year test interval for auxiliary relays. We believe our present maintenance period for auxiliary relays of 10 years is adequate. 2. We also object to the requirement to verify acceptable levels of current values are received by the protective relays. We believe our present current transformer testing practice adequately insures acceptable levels of current are received by the relays and have requested that this procedure be approved. Detailed comments are included with our

Voter	Entity	Segment	Vote	Comment
				responses to the 5 questions in the Comment Form associated with this proposed Standard revision.

Response: **Thank you for your comments.**

1. **The SDT believes that the appropriate interval for devices such as aux or lockout relays remains at 6 years, as these devices contain "moving parts" which must be periodically exercised to remain reliable.**
2. **Please see our response in the Comment Form.**

Voter	Entity	Segment	Vote	Comment
Stan T. Rzad	Keys Energy Services	1	Negative	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 circuity, 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 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

Voter	Entity	Segment	Vote	Comment
				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. The VRF of R1 should be Low since the attached tables are essentially the PSMP.
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 related 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. However, the SDT has made changes to 4.2.1 in consideration of your comment.** **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 the gap.** **4. The SDT disagrees; the Tables establish the intervals and activities, and Requirement R1 addresses the establishment of an entity's individual PSMP.**				
Walt Gill	Lake Worth Utilities	1	Negative	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

Voter	Entity	Segment	Vote	Comment
				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 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 regionsl 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. The VRF of R1 should be Low since the attached tables are essentially the PSMP. 5. Table 1-4 requires a comparison of measured battery internal ohmic value to battery baseline. Since battery manufacturers do not provide this value, it is unclear what the “baseline” values ought to be if an entity recently began performing this test (assuming it’s several years after the commissioning of the battery.) Would it be acceptable for an entity to establish baseline values based on statistical analysis of multiple test results specific to a given battery manufacturer and design? o 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

Voter	Entity	Segment	Vote	Comment
				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 unknowingly 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 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.

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 related 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. However, the SDT has made changes to Applicability 4.2.1 in consideration to your comment.**
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 the gap.**
4. **The SDT disagrees; the Tables establish the intervals and activities, and Requirement R1 addresses the establishment of an entity's individual PSMP.**
5. **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.**
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 detailed discussion.**

Voter	Entity	Segment	Vote	Comment
Larry E Watt	Lakeland Electric	1	Negative	The major reasons are that: 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 circuity, 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 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

Voter	Entity	Segment	Vote	Comment
				electrical 4. the VRF of R1 should be Low since the attached tables are essentially the PSMP.
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 related 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. However, the SDT has made changes to Applicability 4.2.1 in consideration of your comment. 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 the gap. 4. The SDT disagrees; the Tables establish the intervals and activities, and Requirement R1 addresses the establishment of an entity's individual PSMP.				
Joe D Petaski	Manitoba Hydro	1	Negative	1. Implementation Plan (Timeline) for R1: In areas not requiring regulatory approval, the 6 month time frame proposed for R1 is not achievable and is not consistent with areas requiring regulatory approval. To be consistent, the effective 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. 2. VSLs: 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. 3. Table 1-4: The requirements for batteries listed in Table 1-4 do not appear to be consistent with the comments in the FAQ Section (V 1A Example 1). Please see comments submitted during formal comment period for further detail. 4. Table 1-4: 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.

Voter	Entity	Segment	Vote	Comment
Response: Thank you for your comments. 1. 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. 2. The SDT does not understand your concern; further details are needed. 3. 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. 4. The SDT believes that the 3-month interval specified in the Standard is appropriate.				
Terry Harbour	MidAmerican Energy Co.	1	Negative	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 for this testing while minimizing testing outages.
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.				
Saurabh Saksena	National Grid	1	Negative	National Grid believes that this new Requirement as written subjects the Transmission Owner, Generation Owner or Distribution Provider to vague interpretations of what the requirement means by compliance officials. The addition of the new part of Requirement R1 that requires the Owners to “identify calibration tolerances or other equivalent parameters for each Protection System component type” is too intrusive and divisive for what it brings to the reliability of the BES.
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.				
Richard L. Koch	Nebraska Public Power District	1	Negative	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 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

Voter	Entity	Segment	Vote	Comment
				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. 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.) 3. Applicability Part 4.2.5.4 and 4.2.5.5: 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. 4. 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. 5. Requirement R4 Part 4.2: 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

Voter	Entity	Segment	Vote	Comment
				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. 6. Measurement M4: 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.

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.**

Voter	Entity	Segment	Vote	Comment
2. Under frequency load shedding requirements, whether established by regional Entities (current practice) or by EC, are ERO requirements. **3. Clause 4.2.5.5 has been removed. Generator-connected station service transformers are essential to the continuing operation of the generation plant; therefore, protection on these system components is included within PRC-005-2 if the generation plant is a BES facility.** **4. Corrective maintenance is included within PRC-005-2 only in that the initiation of resolution of maintenance-correctable issues (discovered during maintenance activities) in included. The SDT considers the inclusion to be appropriate and necessary as part of the maintenance program.** **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. Corrective maintenance is included within PRC-005-2 only in that the initiation of resolution of maintenance-correctable issues (discovered during maintenance activities) in included. The SDT considers the inclusion to be appropriate and necessary as part of the maintenance program.**				
David H. Boguslawski	Northeast Utilities	1	Negative	1) Requirement 1.5 states “Identify calibration tolerances or other equivalent parameters for each Protection System component type that establish acceptable parameters for the conclusion of maintenance activities”. This requirement is too vague and requires that the owner develop his own acceptable calibration tolerances for “each” protection system component type. The Owners internally generated calibration tolerances would then be subjected to the personal interpretation of what this requirement means by compliance officials and auditors. The confusion and divisiveness that this requirement will create far outweigh its potential benefits. 2) Due to the critical nature of the trip coil, it should be maintained more frequently if it is not monitored. Hence, it would be prudent to increase the test frequency of unmonitored trip coil so that it is more frequent than monitored trip coil. 3) 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? 4) In section D.1.3., the statement regarding data retention for R2 needs to be reworded. The words “performance based maintenance program” should be changed to “time based maintenance program”, since R2 refers to a time based maintenance program.

Voter	Entity	Segment	Vote	Comment
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. 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 can maintain these devices more frequently if you desire. 3. With respect to dc supply associated only with communication 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 have been considered within that activity. 4. The SDT concluded that R2 is redundant with R1, Part 1.4, and has deleted R2 (together with the associated Measure and VSL), and data retention that reflects the previous R2.				
Douglas G Peterchuck	Omaha Public Power District	1	Negative	The three newly added requirements not approved by the drafting team are confusing. 1. OPPD believes that Article 1.4 needs to be deleted from the standard. It is redundant and serves no purpose. 2. OPPD 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. 3. OPPD 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.
Response: Thank you for your comments. 1. 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. However, in consideration to your comment the SDT has revised R1.4 and has also removed R2 because of redundancy to Requirement R1, Part 1.4. 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. 3. 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..				
Chifong L. Thomas	Pacific Gas and Electric Company	1	Negative	1. PG&E submits a Negative vote on Draft 3 of PRC-005-2 due to the addition of Requirement R1, Part 1.5. We do not agree with the addition of Requirement R1, Part 1.5 to the standard, which requires the Owners to "identify calibration tolerances or other equivalent parameters for each Protection System component type". We feel this is too prescriptive and does not belong in the PSMP which should remain at a higher level of detail. This new requirement, as written, can subject the Transmission Owner, Generation Owner or Distribution Provider to vague interpretations

Voter	Entity	Segment	Vote	Comment
				of what the requirement means by compliance officials. Additionally, the new requirement could require documenting thousands of calibration tolerances or other equivalent parameters for companies such as PG&E that use many different types of relays. This level of detail does not belong in the PSMP and would make it nearly impossible to manage. Rather, the calibration tolerances used to test the protection system components should reside in the Transmission Owner, Generation Owner and Distribution Provider's test procedure documents, test macros, or relay instruction manuals. PG&E also has comments on the Implementation Plan document. 2. PG&E does not agree with the time frames listed for implementation of Requirements R1, R2, R3 and R4, as explained below: a. Implementation plan for Requirement R1: Time was extended from three months to twelve months following regulatory approval which we agree with. For those jurisdictions where no regulatory approval is required it would seem that the time frame should also be extended to at least twelve months following NERC Board approval. However, it is still listed as six months following NERC Board approval. b. Implementation plan for Requirements R2, R3 and R4: For Protection System Components with maximum allowable intervals less than 1 year, it does not make sense to require 100% compliance after twelve months following regulatory approval, when this is the same time frame for compliance with Requirement R1 for establishment of the new PSMP. The implementation time window for Requirements R2, R3 and R4 should follow the implementation of Requirement R1 which establishes the new PSMP. So the dates listed for 100% compliance with Requirements R2, R3 and R4 should all be pushed out by 12 months each. c. Following is a summary time line for suggested implementation requirements. o Months 1-12 Establish PSMP per R1 i. Month 12+ Begin performing maintenance under new PSMP ii. Month 24 100% compliance date for R2, R3, R4, for components with max allowable intervals less than 1 year. iii. 3 Calendar Years 100% compliance date for R2, R3, R4, for components with max allowable intervals 1 year or more, but 2 years or less.

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td></td><td>iv. 3 Calendar Years 30% compliance date for R2, R3, R4, for components with max allowable intervals of 6 years.
v. 5 Calendar Years 60% compliance date for R2, R3, R4, for components with max allowable intervals of 6 years.
vi. 7 Calendar Years 100% compliance date for R2, R3, R4, for components with max allowable intervals of 6 years.
3. Overall the updated standard is a huge improvement over Draft 2 in terms of structure of the tables and presentation, which simplifies the standard quite a bit. PG&E would have been in support of Draft 3 if the requirement R1.5 had not been added.</td></tr>
<tr><td colspan="5">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 Implementation Plan for R1 has been changed from six months to twelve months, and the Implementation Plan for Protection System Components with maximum allowable intervals less than 1 year has been changed from 12 months to 15 months in consideration of your comment. The Implementation Plan for R4 has been revised to add one year to all established dates.
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.</td></tr>
<tr><td>Brenda L Truhe</td><td>PPL Electric Utilities Corp.</td><td>1</td><td>Negative</td><td>PPL Electric Utilities (“PPL EU”) appreciate the hard work and efforts of the Standards Drafting Team in reaching this point in the standards development process. The basis for the negative vote is the addition of Requirement R1.5 (calibration tolerances) and R4.2 to the standard. This requirement will provide the opportunity for auditors to decide if the testing criteria for whether a relay passes a test or not is acceptable. PPL EU recommends that Requirement R1.5 be deleted from the standard.</td></tr>
<tr><td colspan="5">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.</td></tr>
<tr><td>Kenneth D. Brown</td><td>Public Service Electric and Gas Co.</td><td>1</td><td>Negative</td><td>The PSEG Companies do not agree with the Facilities as currently described in section 4.2.5.5. Please refer to detailed comments provided in the formal Comment Form.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments. Please see our responses to your comments from the formal comment period.</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
Pawel Krupa	Seattle City Light	1	Negative	Comment: The proposed Standard PRC-005-2 is an improvement over the previous draft in that it provides more consistency in maintenance and testing duration internals. Notwithstanding, two issues are of concern to Seattle City Light such that it is compelled to vote no: 1) the establishment of bookends for standard verification and 2) the implementation timelines for entities with systems where electro-mechanical relays still compose a significant number of components in their protection systems. 1. Bookends: Proposed Standard PRC-005-2 specifies long inspection and maintenance intervals, up to 12 years, which correspondingly exacerbates the so-called "bookend" issue. To demonstrate that interval-based requirements have been met, two dates are needed - bookends. Evidencing an initial date can be problematic for cases where the initial date would occur prior to the effective date of a standard. NERC has provided no guidance on this issue, and the Regions approach it differently. Some, such as Texas Regional Entity, require initial dates beginning on or after the effective date of a Standard. Compliance with intervals is assessed only once two dates are available that occur on or after a standard took effect. Other regions, such as Western Electricity Coordinating Council (WECC), require that entities evidence an initial date prior to the effective date of a standard. For WECC, compliance with intervals is assessed as soon as a standard takes effect. Such variation makes application of standards involving bookends uncertain, arbitrary, capricious, and in the case of WECC, possibly illegal. Proposed Standard PRC-005-2 will be another such standard. Indeed this Standard will involve by far the largest number of bookends of any NERC standard - many thousands for a typical entity. Furthermore, the long inspection and maintenance intervals introduced in the draft will require entities in WECC, for instance, to evidence initial bookend dates prior to the date original PRC-005-1 took effect. For the 12-year intervals for CTs and VTs in proposed Standard PRC-005-2, many initial dates will occur prior to the 2005 Federal Power Act that authorized Mandatory Reliability Standards and even reach back before the 2003 blackout that catalyzed the effort to pass the Federal Power Act. As a result, many entities in WECC maybe at risk of being found in violation of proposed Standard PRC-005-2 immediately upon its implementation. Seattle City Light requests that NERC address the bookends issue, either within proposed Standard PRC-005-2 or in a

Voter	Entity	Segment	Vote	Comment
				separate, concurrent document. 2. Legacy Systems: Many entities still have legacy protection systems that rely upon electro-mechanical relays. Effective testing approaches differ between electro-mechanical and digital relay systems. Thus, although the proposed standard rightly looks to the future of digital relays by specifying testing and maintenance focused on protection systems as a whole, the proposed implementation timelines create a level of hardship for those utilities with legacy systems. In example, auxiliary relay and trip coil testing may be essential to prove the correct operation of complex, multi-function digital protection systems. However, for legacy systems with single-function electro-mechanical components, the considerable documentation and operational testing needed to implement and track such testing is not necessarily proportional to the relative risk posed by the equipment to the bulk electric system. Performance testing of electro-mechanical systems, particularly regarding control circuits, will require extensive disconnection and reconnection of portions of the circuits. Such activities will likely cause far more problems on restoration-to-service than they will locate and correct. As such, to assist entities in their implementation efforts, we believe provision of alternatives are necessary, such as additional implementation time through phasing and/or through technical feasability exceptions.
Response: **Thank you for your comments.** **1. This issue has been addressed by NERC in Compliance Application Notice CAN-008 "PRC-005 R2 Pre-June 18 Evidence".** **2. Please see Sections 8 and 15.3 of the Supplementary Reference Document for a discussion on this topic. FERC Order 693 directs that NERC establish requirements for the maintenance of the Protection System and control circuitry is a portion thereof. Therefore, requirements for the maintenance of the control circuitry are necessary and the SDT has developed those requirements in a fashion that affords entities with the opportunity to best meet those requirements.**				
Horace Stephen Williamson	Southern Company Services, Inc.	1	Negative	Reference the new Requirements R.1.5 and R.4.2 which are new to this posting: R.1.5 requires the Owners to "identify calibration tolerances or other equivalent parameters for each Protection System component type" is too intrusive and divisive for what it brings to the reliability of the BES. The entire SDT needs to thoroughly discuss these new requirements and modify or delete them. Note: We have also made various requests for clarification to the FAQ and Supplemental Reference document in our Response to Comments which we are not including here.
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.**				

Voter	Entity	Segment	Vote	Comment
Larry Akens	Tennessee Valley Authority	1	Negative	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 “NO” because of the hurried fashion it is being commented, voted, and reviewed.
Response: **Thank you for your comments. Because of the urgent priority placed on this Standard by NERC, this Standard was posted for a 30-day formal comment period with a concurrent 10-day ballot period at the conclusion of that comment period, even though the Standard Development Process allows for a maximum 45-day formal comment period.**				
Brandy A Dunn	Western Area Power Administration	1	Negative	1) Western disagrees with the requirement R1, Part 1.5 that requires identifying "calibration tolerances or equivalent parameters for each Protection System component~" This requirement will add a burdensome, manual documentation of thousands of tolerances and parameters that are now part of multiple automated software programs and routines. These programs were purchased and developed over numerous years of testing experience by Western and testing equipment manufacturers. The fact that these tolerance and parameters are automated to Pass/Fail program notifications, gives our Maintenance Divisions repeatable testing programs that are not dependent on personnel interpretations. Extracting all these tolerances and parameters from these programs provides no benefit for our PSMP. 2) Western disagrees with the wording of the R4.2 requirement referencing the Part 1.5 of R1. The requirements of R4 are that you are to perform the appropriate maintenance activity and the associated testing. The fact that the testing was done and the equipment passed the testing meets the compliance for R4. If the equipment fails the testing, it then becomes a maintenance correctable issue, that requires adjustment or replacing, with further testing until the equipment passes the required testing. Documenting thousands of tolerances and parameters, for possibly thousands of components, serves no useful purpose for our PSMP or compliance documentation.
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.**				
Gregory L Pieper	Xcel Energy, Inc.	1	Negative	“We feel that several improvements were made since the last draft. However, we feel that some gaps exist that should be addressed before moving this project forward. We have detailed our issues in our formal comments.”
Response: **Thank you for your comments. Please see our responses to your comments from the formal comment period.**				

Voter	Entity	Segment	Vote	Comment
Kim Warren	Independent Electricity System Operator	2	Negative	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 Document, Section 8 for a discussion of this.** **2. 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**				
Richard J. Mandes	Alabama Power Company	3	Negative	Reference the new Requirements R.1.5 and R.4.2 which are new to this posting: R.1.5 requires the Owners to "identify calibration tolerances or other equivalent parameters for each Protection System component type" is too intrusive and divisive for what it brings to the reliability of the BES. The entire SDT needs to thoroughly discuss these new requirements and modify or delete them. Note: We have also made various requests for clarification to the FAQ and Supplemental Reference document in our Response to Comments which we are not including here.
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.**				
Bob Reeping	Allegheny Power	3	Negative	Allegheny Power applauds the hard work that the Standards Draft Team has exhibited in producing a clear and enforceable standard that will increase the reliability of the Bulk Electric System. However, the addition of requirement 1.5 is such a significant change in scope from the last draft that a further review of the potential impact and any implementation concerns is required by AP and the industry in general before we can consider voting in-favor of this standard.

Voter	Entity	Segment	Vote	Comment
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.				
Raj Rana	American Electric Power	3	Negative	Restructured Tables: 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. Also, unmonitored control circuitry is capitalized in row 4 such that it infers a defined term. 2. 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. 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. VSLs, VRFs and Time Horizons: 3. The VSL table should be revised to remove the reference to the Standard Requirement 1.5 in the R1 “High” VSL. 4. All four levels of the VSL for R2 make reference to a “condition-based PSMP.” However, nowhere 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. 5. 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. FAQ and Supplementary Reference:

Voter	Entity	Segment	Vote	Comment
				6. 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: a. Section 5 of the Supplementary Reference, refers to "condition-based" maintenance programs. However, nowhere 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. b. Section 15.7, page 26, appears to have a typographical error "…can all be used as the primary action is the maintenance activity…" c. 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. "Frequently-Asked Questions": 7. 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: a. The section "Terms Used in PRC-005-2" is blank and should be removed as it adds no value. b. Section I.1 and Section IV.3.G reference "condition-based" maintenance programs. However, nowhere 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. c. 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…". General:

Voter	Entity	Segment	Vote	Comment
				8. 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. 9. 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 a knowledge of material in the Supplementary Reference or FAQ. 10. “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. 11. 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: **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 circuitry. The capitalized term has been corrected and additional changes have been made.**
2. **Table 1-4 has been modified in consideration of your comments.**
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.**

Voter	Entity	Segment	Vote	Comment

4. The SDT concluded that Requirement R2 is redundant to Requirement R1, Part 1.4 and has deleted Requirement R2 (together with the Measures and & VSL).

5. If the indicated monitoring attributes are present, no "hands-on" periodic maintenance is required, as the monitoring of the component is providing a continuing indication of its functionality.

6. The discussion within the Supplementary Reference and FAQ are informative, not normative, and thus do not belong as part of the standard.

   D. 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. 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.

   E. This clause has been corrected.

7. The discussion within the Supplementary Reference and FAQ are informative, not normative, and thus do not belong as part of the standard.

   b) 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.
   c) 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.
   d) 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.

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. 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.

10. "Protective relay" is defined by IEEE, and the SDT sees no need to either change the definition or to repeat the definition with PRC-005. Further, the applicability of generically-described protective relays is defined by the Applicability clause of PRC-005-2.

11. 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.

Voter	Entity	Segment	Vote	Comment
Rebecca Berdahl	Bonneville Power Administration	3	Negative	Please refer to BPA's submitted comments on 12/16/10.
Response: **Thank you for your comments. Please see our responses to your comments from the formal comment period.**				
Steve Alexanderson	Central Lincoln PUD	3	Affirmative	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 FAQ 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.**				
Gregg R Griffin	City of Green Cove Springs	3	Negative	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 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.

Voter	Entity	Segment	Vote	Comment
				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. the VRF of R1 should be Low since the attached tables are essentially the PSMP.
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 related 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. However, the SDT has made changes to Applicability 4.2.1 in consideration of your comments.** **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 the gap.** **4. The SDT disagrees; the Tables establish the intervals and activities, and Requirement R1 addresses the establishment of an entity's individual PSMP.**				
Bruce Krawczyk	ComEd	3	Negative	The addition of the requirement R1.5 and associated wording has resulted in Exelon to vote No on the standard. While Exelon does specify Protection System tolerances and parameters in many maintenance documents; attempting to establish documented requirements for each component type is not practical. Additionally, this can leave much to the discretion of an auditor as to how in-depth tolerances need to be. There are many equipment and applications variations, many of which can utilize generic values while others require very specific value

Voter	Entity	Segment	Vote	Comment
				ranges. There are many instances where a very specific component tolerance is required for one application, but the same component doesn't require a tolerance in a different application. This could lead to entities having to justify why one application with a common component requires a narrow range versus the same component in another application can use a generic value or no tolerance. The last part of the requirement is also not clear. If a parameter is established, the R1.5 requirement is inferring component must meet an acceptable parameter to conclude the maintenance activity. There are many instances when a component is found out of a tolerance, but the level does not require immediate action and can even be scheduled for remediation at the next maintenance cycle. The wording in R1.5 appears to conflict with the R4.2 which indicates maintenance activities can be conclude as long as corrective maintenance is initiated as a result of identifying the condition.
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.**				
Peter T Yost	Consolidated Edison Co. of New York	3	Negative	The Tables - 1. 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. 2. The "Note" included in the heading is also not necessary. "Attributes" is also not necessary in the column heading, "Component" suffices. Other Comments – 3. 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. 4. 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

Voter	Entity	Segment	Vote	Comment
				are oftentimes connected in tripping or control circuits to isolate problem equipment. 5. 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. 6. 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? 7. 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. 8. 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. 9. A control circuit is not a component, it is made up of components. 10. 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. 11. In the Implementation plan for Requirement R1, recommend changing

Voter	Entity	Segment	Vote	Comment
				"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. 12. 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. 13. 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.

Response: Thank you for your comments.

1. The SDT believes that the table headings are appropriate as reflected in the draft standard.

2. The SDT believes that the table headings are appropriate as reflected in the draft standard.

3. The intervals and activities specified are believed by the SDT to be technically effective, in a fashion that may be consistently monitored for compliance. Further, FERC Order 693 directs NERC to establish maximum allowable intervals, which implies that minimum activities also need to 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.

4. 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.

5. 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 can maintain these devices more frequently if you desire

6. With respect to dc supply associated only with communication 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

Voter	Entity	Segment	Vote	Comment
specific station dc supply requirements (Table 1-4) do not apply to the dc supply associated only with communications systems. 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. 7. 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 used here. They are defined only for clarify within this standard. 8. 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. 9. For purposes of this standard, the control circuit IS defined as one component type. 10. 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. 11. In consideration of your comment, "six" has been modified to "twelve" in the Implementation Plan for R1, making it consistent with the remainder of the Implementation Plan. 12. Table 1-4 has been further modified for clarity. 13. In response to many comments, including yours, the SDT has removed 4.2.5.5 from the Applicability of the standard.				
David A. Lapinski	Consumers Energy	3	Negative	We have the following comment on the revisions, specifically sub-requirement R1.12a, which states, "Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.". We have no issue with this requirement on transmission lines that are 200 kV or greater. However, we do have a concern with applying requirement R1.12a on lower voltage lines now that the Transmission Relay Loadability Standard is being revised to included selected equipment 200 kV and below. The positive-sequence line angle on lower voltage lines, such as 69 kV or 46 kV, is significantly lower than 90 degrees. The positive-sequence line angle for 3/0 ACSR, for example, is only 55 degrees. Setting a 90 degree MTA on these lines would require a much larger reach setting to provide adequate line protection. In some cases, especially for lines with long spurs and poor line conductor, the increased reach setting may actually provide less loadability than a reach setting based on an MTA set at the positive-sequence line angle. A 90 degree MTA also dramatically reduces the resistive fault coverage for these lines. For these reasons, we would propose a modification to sub-

Voter	Entity	Segment	Vote	Comment
				requirement R1.12a as follows: Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer on 200 kV or greater transmission lines. Set the maximum torque angle (MTA) to the positive-sequence line angle on transmission lines less than 200 kV.
Response: **Thank you for your comments. This comment appears to apply to PRC-023-2 (Project 2010-17), which is a separate activity, and is not apparently relevant to PRC-005-2.**				
Michael F Gildea	Dominion Resources Services	3	Negative	Dominion is opposed to this version because Requirement R1.5 is overly prescriptive, requiring an extraordinary level of documentation, with little anticipated improvement in 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.**				
Henry Ernst-Jr	Duke Energy Carolina	3	Negative	1. 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. 2. 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 3. 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. 4. 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. 5. VSL for R1 - Sub-requirement R1.3 appears to be missing. 6. 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. 7. VSL for 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. 8. There are typographical errors on the FAQ Requirements Flowchart (should

Voter	Entity	Segment	Vote	Comment
				be R4.1.1 and R4.1.2 instead of R4.4.1 and R4.4.2). 9. 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.

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. 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 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.

4. Table 2 has been modified to be clearer. "Taken" has been replaced with "Initiation" in consideration of your comment.

5. The High VSL for Requirement R1 has been revised in consideration of your comment.

6. The issues of "monitoring attributes" are discussed within Section 15.7 of the Supplementary Reference Document. As for Requirement R1, Part 1.5, 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.

7. Examples of compliance documentation are included within Measure M4 and discussed within various clauses of the FAQ and within Section 15.7 of the Supplementary Reference Document.

8. 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.

9. The SDT decided to eliminate the FAQ document and incorporate the FAQ's contents into the Supplementary Reference Document as appropriate. The SDT believes the 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.

Voter	Entity	Segment	Vote	Comment
Joel T Plessinger	Entergy	3	Negative	The restructured tables are generally much clearer and the SDT is to be commended on their efforts. 1. 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 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? 2. 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? R1.5 calls for "identification of calibration tolerances or equivalent parameters for each Protection System Component Type….". 3. 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 for a component type besides protective relays. Adding Requirement 1.5 is a significant revision and raises questions as to how broadly an accuracy or equivalent parameter requirement and associated

Voter	Entity	Segment	Vote	Comment
				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.** **1. The Maximum Maintenance Interval column entry in Table 2 has been revised to state, "When alarm producing Protection System component is verified" to clarify 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 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.**				
Kevin Querry	FirstEnergy Solutions	3	Negative	Please see FirstEnergy's comments submitted separately through the comment period posting.
Response: **Thank you for your comments. Please see our responses to your comments from the formal comment period.**				
Lee Schuster	Florida Power Corporation	3	Negative	Implementation Plan for PRC-005-2 1. Since R2, R3, and R4 requirements would be performed after establishment of the program documentation, an additional year should be added to all implementation dates for Requirements R2, R3, and R4 as shown below: • Maintenance on components with intervals less than one year must be completed within two years after applicable regulatory approval (within one year of completion of R1 Program Documentation). • Maintenance on components with intervals between one year and two years must be completed within three years after applicable regulatory approval (within two years of completion of R1 Program Documentation). • Maintenance on components with intervals of six years must be completed within three-, five-, and seven-year milestones after

Voter	Entity	Segment	Vote	Comment
				applicable regulatory approval (within two, four, and six years of completion of R1 Program Documentation). • Maintenance on components with intervals of twelve years must be completed within five-, nine-, and thirteen-year milestones after applicable regulatory approval (within four, eight, and twelve years of completion of R1 Program Documentation). Standard PRC-005-02 1. 2. Table 1-2: Rows 1 and 2 require different intervals for the activity “Verify essential signals to and from Protection System components.” Unless these inputs and outputs are monitored for Row 2, it would seem that they should be performed at the same interval for both Rows 1 and 2. Therefore, EITHER: • Row 1 should be broken into the following three activities: • 3 months - Verify communications system is functional • 6 years - Verify channel meets performance criteria • 12 years - Verify essential signals to and from other Protection System components OR: • Row 2 should be broken into the following two activities: • 12 years - Verify channel meets performance criteria • 6 years - Verify essential signals to and from other Protection System components 3. Table 1-4: Only Row 1 addresses dc supplies associated with UFLS or UVLS systems. All other rows state that UFLS or UVLS systems are excluded. What is required to “Verify dc supply voltage” for the UFLS/UVLS systems? Does it require that the overall station battery voltage be checked or just the dc voltage available to the UFLS/UVLS circuit of interest? If a voltage measurement is taken at the UFLS/UVLS circuit (e.g., in distribution breaker cabinet), can the batteries/chargers at these facilities be excluded from the PRC-005-2 scope as long as they do not also supply transmission-related protection? 4. PRC-005-2 FAQ’s Document Section V.1.A, Example #2: The instrument transformer should be classified as “unmonitored” not “monitored.”

Response: **Thank you for your comments.**

1. **The Implementation Plan for Requirement R1 has been changed from 12 months to 15 months in consideration of your comment. The Implementation Plan for Requirement R4 has been revised to add one year to all established dates.**
2. **The first and second rows differ in that the first row is for unmonitored communications systems, and the second row is for monitored communications systems. The activities in both rows are appropriate and correct.**
3. **Table 1-4 has been completely re-structured. For station dc supply for only UFLS/UVLS, the only activity is to verify the dc**

Voter	Entity	Segment	Vote	Comment
voltage. 4. 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.				
Anthony L Wilson	Georgia Power Company	3	Negative	Reference the new Requirements R.1.5 and R.4.2 which are new to this posting: R.1.5 requires the Owners to "identify calibration tolerances or other equivalent parameters for each Protection System component type" is too intrusive and divisive for what it brings to the reliability of the BES. The entire SDT needs to thoroughly discuss these new requirements and modify or delete them. Note: We have also made various requests for clarification to the FAQ and Supplemental Reference document in our Response to Comments which we are not including here.
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.				
Michael D. Penstone	Hydro One Networks, Inc.	3	Negative	1. The added requirement R1, Part 1.5 is vague and needs clarification. It is not clear what "Identify calibration tolerances or other equivalent parameters" means and as written will be subject to different interpretations by entities and compliance enforcement personnel. The addition of this new part of Requirement R1 that requires the Owners to "identify calibration tolerances or other equivalent parameters for each Protection System component type" is onerous and contributes little to the reliability of the BES. 2. Changes introduced to the Implementation Plan since the last posting are not consistent with respect to jurisdictions where no regulatory approval is required. The previously posted implementation for Requirement R1 required entities to be 100% compliant on the first day of the first calendar quarter three months following applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter six months following Board of Trustees adoption. The amended implementation plan changed the three-month time to twelve months in jurisdictions with regulatory approval required but left the same six-month time for the others. For consistency, the six months timeframe should be changed to fifteen 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 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.				

Voter	Entity	Segment	Vote	Comment
2. 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.				
Garry Baker	JEA	3	Negative	JEA will be voting no on PRC-005-2 because of the following: 1. In Table 1-1 for electromechanical trip or auxiliary devices requires verification of operation as opposed to verify ability to operate that was specified on trip coils. I believe it should be ability to operate in each case. 2. Between Table 1-1 and Tables 1-5 essentially would require full functional test of each station every 12 years.
Response: Thank you for your comments. 1. The distinction in Table 1-5 is correct and as intended by the SDT. 2. A full functional test is one means of completing the required activities, but other methods are also acceptable. See Sections 8 and 15.3 of the Supplementary Reference Document for additional discussion.				
Mace Hunter	Lakeland Electric	3	Negative	1. Table 1-4 requires a comparison of measured battery internal ohmic value to battery baseline. Since battery manufacturers do not provide this value, it is unclear what the “baseline” values ought to be if an entity recently began performing this test (assuming it’s several years after the commissioning of the battery.) Would it be acceptable for an entity to establish baseline values based on statistical analysis of multiple test results specific to a given battery manufacturer and design? 2. Lakeland feels that the SDT should have taken into consideration numerous comments previously made regarding general concerns with testing Control Circuitry in energized substations. We agree that this can negatively impact reliability and would like to emphasize the following: • 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.) • 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 unknowingly 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 circuitry where this may not be the case is in the inter and intra-panel

Voter	Entity	Segment	Vote	Comment
				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. 3. 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" 4. 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 5. the VRF of R1 should be Low since the attached tables are essentially the PSMP.

Response: **Thank you for your comments.**

1. **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.**
2. **A) 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.**

   B) 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 detailed discussion.
3. **This interpretation is not yet approved by FERC. When this interpretation is approved, the SDT will incorporate it within PRC-005-2. However, the SDT has made changes to Applicability 4.2.1 in consideration of your comments.**
4. **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 the gap.**

Voter	Entity	Segment	Vote	Comment
5. **The SDT disagrees; the Tables establish the intervals and activities, and R1 addresses the establishment of an entities' individual PSMP.**				
Bruce Merrill	Lincoln Electric System	3	Affirmative	While the proposed draft of the standard is acceptable as currently written, LES would like the drafting team to consider the following comments. (1) Table 1-1 should state "Test and calibrate (if necessary)" in the first section under activities. If a relay passes the test, there is no need to calibrate it. Therefore, not all relays will require calibration. (2) Please explain the drafting team's reason for not checking the trip coils of breakers in the UFLS/UVLS schemes but ensuring that all others are operated every six years. It would appear that they can all be lumped into the same group one way or another. (3) In regards to Specific Gravity Testing, many people do not perform the specific gravity test routinely if they perform the individual cell internal ohmic test routinely. LES asks the drafting team to consider allowing the internal cell ohmic test as a substitute for the specific gravity test.
Response: Thank you for your comments. 1. **Table 1-1 has been modified as you suggest.** 2. **This is an intentional difference between UFLS/UVLS and the remainder of the Protection Systems addressed within the Standard, because of the distributed nature of UFLS/UVLS and because these devices are usually tripping distribution system elements.** 3. **Table 1-4 does not specify specific gravity testing.**				
Charles A. Freibert	Louisville Gas and Electric Co.	3	Negative	LG&E and KU Energy LLC appreciate the hard work and efforts of the Standards Drafting Team in reaching this point in the standards development process. The basis for the negative vote is the addition of Requirement R1.5 (calibration tolerances) and R4.2 to the standard. This requirement will provide the opportunity for auditors to decide if the testing criteria for whether a relay passes a test or not is acceptable. LG&E and KU Energy recommend that Requirement R1.5 be deleted from the standard.
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.				
Greg C. Parent	Manitoba Hydro	3	Negative	1. -Implementation Plan (Timeline) for R1: In areas not requiring regulatory approval, the 6 month time frame proposed for R1 is not achievable and is not consistent with areas requiring regulatory approval. To be consistent, the effective 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.

Voter	Entity	Segment	Vote	Comment
				2. - VSLs: 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. 3. -Table 1-4: The requirements for batteries listed in Table 1-4 do not appear to be consistent with the comments in the FAQ Section (V 1A Example 1). Please see comments submitted during the formal comment period for further detail. 4. -Table 1-4: 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.
Response: **Thank you for your comments.** **1. 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.** **2. The SDT does not understand your concern; further details are needed.** **3. 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.** **4. The SDT believes that the 3-month interval specified in the Standard is appropriate.**				
Don Horsley	Mississippi Power	3	Negative	Reference the new Requirements R.1.5 and R.4.2 which are new to this posting: R.1.5 requires the Owners to “identify calibration tolerances or other equivalent parameters for each Protection System component type” is too intrusive and divisive for what it brings to the reliability of the BES. The entire SDT needs to thoroughly discuss these new requirements and modify or delete them. Note: We have also made various requests for clarification to the FAQ and Supplemental Reference document in our Response to Comments which we are not including here.
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.**				
Michael Schiavone	Niagara Mohawk (National Grid Company)	3	Negative	This new Requirement as written subjects the Transmission Owner, Generation Owner or Distribution Provider to vague interpretations of what the requirement means by compliance officials. The addition of the new part of Requirement R1 that requires the Owners to “identify calibration tolerances or other equivalent parameters for each Protection System component type” is too intrusive and divisive for what it brings to the reliability of the BES.

Voter	Entity	Segment	Vote	Comment
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.**				
Sam Waters	Progress Energy Carolinas	3	Negative	4. Implementation Plan for PRC-005-2 Since R2, R3, and R4 requirements would be performed after establishment of the program documentation, an additional year should be added to all implementation dates for Requirements R2, R3, and R4 as shown below: • Maintenance on components with intervals less than one year must be completed within two years after applicable regulatory approval (within one year of completion of R1 Program Documentation). • Maintenance on components with intervals between one year and two years must be completed within three years after applicable regulatory approval (within two years of completion of R1 Program Documentation). • Maintenance on components with intervals of six years must be completed within three-, five-, and seven-year milestones after applicable regulatory approval (within two, four, and six years of completion of R1 Program Documentation). o Maintenance on components with intervals of twelve years must be completed within five-, nine-, and thirteen-year milestones after applicable regulatory approval (within four, eight, and twelve years of completion of R1 Program Documentation). Standard PRC-005-02 1. 5. Table 1-2: 1. Rows 1 and 2 require different intervals for the activity “Verify essential signals to and from Protection System components.” Unless these inputs and outputs are monitored for Row 2, it would seem that they should be performed at the same interval for both Rows 1 and 2. Therefore, EITHER: • Row 1 should be broken into the following three activities: • 3 months - Verify communications system is functional • 6 years - Verify channel meets performance criteria • 12 years - Verify essential signals to and from other Protection System components OR: • Row 2 should be broken into the following two activities: • 12 years - Verify channel meets performance criteria • 6 years - Verify essential signals to and from other Protection System components. 6. Table 1-4: Only Row 1 addresses dc supplies associated with UFLS or UVLS systems. All other rows state that UFLS or UVLS systems are excluded. What

Voter	Entity	Segment	Vote	Comment
				is required to "Verify dc supply voltage" for the UFLS/UVLS systems? Does it require that the overall station battery voltage be checked or just the dc voltage available to the UFLS/UVLS circuit of interest? If a voltage measurement is taken at the UFLS/UVLS circuit (e.g., in distribution breaker cabinet), can the batteries/chargers at these facilities be excluded from the PRC-005-2 scope as long as they do not also supply transmission-related protection? 7. PRC-005-2 FAQ's Document Section V.1.A, Example #2: The instrument transformer should be classified as "unmonitored" not "monitored."
Response: **Thank you for your comments.** **4. The Implementation Plan for Requirement R1 has been changed from 12 months to 15 months in consideration of your comment. The Implementation Plan for Requirement R4 has been revised to add one year to all established dates.** **5. The first and second rows differ in that the first row is for unmonitored communications systems, and the second row is for monitored communications systems. The activities in both rows are appropriate and correct.** **6. Table 1-4 has been completely re-structured. For station dc supply for only UFLS/UVLS, the only activity is to verify the dc voltage.** 7. **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.**				
Jeffrey Mueller	Public Service Electric and Gas Co.	3	Negative	The PSEG Companies do not agree with the Facilities as currently described in section 4.2.5.5. Please refer to detailed comments provided in our formal Comment Form.
Response: **Thank you for your comments. In response to many comments, including yours, the SDT has removed 4.2.5.5 from the Applicability of the standard.**				
Anthony Schacher	Salem Electric	3	Negative	Battery testing methodologies are too specific and don't allow for different substation battery configurations.
Response: **Thank you for your comments. The SDT disagrees; the requirements within Table 1-4 establish the minimum maintenance activities required to assure that station dc supply of various technologies and configurations will perform as intended without unnecessarily prescribing specific methodologies.**				
Dana Wheelock	Seattle City Light	3	Negative	Comment: The proposed Standard PRC-005-2 is an improvement over the previous draft in that it provides more consistency in maintenance and testing duration internals. Notwithstanding, two issues are of concern to Seattle City Light such that it is compelled to vote no: 1) the establishment of bookends for standard verification and 2) the implementation timelines for entities with systems where electro-mechanical

Voter	Entity	Segment	Vote	Comment
				relays still compose a significant number of components in their protection systems. Bookends: Proposed Standard PRC-005-2 specifies long inspection and maintenance intervals, up to 12 years, which correspondingly exacerbates the so-called "bookend" issue. To demonstrate that interval-based requirements have been met, two dates are needed - bookends. Evidencing an initial date can be problematic for cases where the initial date would occur prior to the effective date of a standard. NERC has provided no guidance on this issue, and the Regions approach it differently. Some, such as Texas Regional Entity, require initial dates beginning on or after the effective date of a Standard. Compliance with intervals is assessed only once two dates are available that occur on or after a standard took effect. Other regions, such as Western Electricity Coordinating Council (WECC), require that entities evidence an initial date prior to the effective date of a standard. For WECC, compliance with intervals is assessed as soon as a standard takes effect. Such variation makes application of standards involving bookends uncertain, arbitrary, capricious, and in the case of WECC, possibly illegal. Proposed Standard PRC-005-2 will be another such standard. Indeed this Standard will involve by far the largest number of bookends of any NERC standard - many thousands for a typical entity. Furthermore, the long inspection and maintenance intervals introduced in the draft will require entities in WECC, for instance, to evidence initial bookend dates prior to the date original PRC-005-1 took effect. For the 12-year intervals for CTs and VTs in proposed Standard PRC-005-2, many initial dates will occur prior to the 2005 Federal Power Act that authorized Mandatory Reliability Standards and even reach back before the 2003 blackout that catalyzed the effort to pass the Federal Power Act. As a result, many entities in WECC maybe at risk of being found in violation of proposed Standard PRC-005-2 immediately upon its implementation. Seattle City Light requests that NERC address the bookends issue, either within proposed Standard PRC-005-2 or in a separate, concurrent document. 2) Legacy Systems: Many entities still have legacy protection systems that rely upon electro-mechanical relays. Effective testing approaches differ between electro-mechanical and digital relay systems. Thus, although the proposed standard rightly looks to the future of digital relays by specifying testing and maintenance focused on protection systems as a whole, the proposed implementation timelines create a level of hardship for those utilities with legacy systems. In example, auxiliary relay and trip coil testing may be essential to prove the correct operation of complex, multi-function digital protection systems. However, for legacy systems with single-function

Voter	Entity	Segment	Vote	Comment
				electro-mechanical components, the considerable documentation and operational testing needed to implement and track such testing is not necessarily proportional to the relative risk posed by the equipment to the bulk electric system. Performance testing of electro-mechanical systems, particularly regarding control circuits, will require extensive disconnection and reconnection of portions of the circuits. Such activities will likely cause far more problems on restoration-to-service than they will locate and correct. As such, to assist entities in their implementation efforts, we believe provision of alternatives are necessary, such as additional implementation time through phasing and/or through technical feasibility exceptions.
Response: **Thank you for your comments.** **1. This issue has been addressed by NERC in Compliance Application Notice CAN-008 "PRC-005 R2 Pre-June 18 Evidence". Please see Sections 8 and 15.3 of the Supplementary Reference Document for a discussion on this topic.** **2. FERC Order 693 directs that NERC establish requirements for the maintenance of the Protection System and control circuitry is a portion thereof. Therefore, requirements for the maintenance of the control circuitry are necessary and the SDT has developed those requirements in a fashion that affords entities with the opportunity to best meet those requirements.**				
James R. Keller	Wisconsin Electric Power Marketing	3	Negative	Q4: 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.**				
Michael Ibold	Xcel Energy, Inc.	3	Negative	See comments under the Transmission segment.
Response: **Thank you for your comments. Please see our responses to your comments from the Transmission segment.**				
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Negative	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. i. 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

Voter	Entity	Segment	Vote	Comment
				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.
Response: **Thank you for your comments. 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 Documentation has been revised to clarify.**				
David Frank Ronk	Consumers Energy	4	Negative	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. 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

Voter	Entity	Segment	Vote	Comment
				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: **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 "six" months to "twelve" 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, and 1106 all recommend this activity at a 12-month interval. Please see Clause 15.4.1 of the Supplementary Reference Document for a discussion of this activity.** 5. **Re-torqueing the battery terminals would not meeting this requirement.**				
Frank Gaffney	Florida Municipal Power Agency	4	Negative	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 circuity, 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 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

Voter	Entity	Segment	Vote	Comment
				ensure that the regionsl 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 the VRF of R1 should be Low since the attached tables are essentially the PSMP.

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 related 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. However, the SDT has made changes to Applicability 4.2.1 in consideration of your comments.**

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 the gap.**

Voter	Entity	Segment	Vote	Comment
Thomas W. Richards	Fort Pierce Utilities Authority	4	Negative	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 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 2009-10 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

Voter	Entity	Segment	Vote	Comment
				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 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 related 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. However, the SDT has made changes to Applicability 4.2.1 in consideration of your comments.**

Voter	Entity	Segment	Vote	Comment
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 the 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 detailed discussion.				
Bob C. Thomas	Illinois Municipal Electric Agency	4	Negative	It is IMEA's understanding from interaction with other entities that Draft 3 provides significant improvement, but that key concerns raised by many entities on Draft 2 were not addressed. IMEA supports comments submitted by Florida Municipal Power Agency.
Response: Thank you for your comments. Please see our responses to your comments submitted during the Formal Comment period..				
Christopher Plante	Integrys Energy Group, Inc.	4	Negative	Reason for No Vote: 1. Implementation plan is too aggressive given the drastic changes from PRC-005-1 to PRC-005-2 2. The drastic changes don't appear to provide an incremental increase in the reliability of the BES 3. We support the MRO NSRS comments
Response: Thank you for your comments. 1. The SDT has carefully considered the changes that entities will be expected to make to their program in response to PRC-005-2 and provided an Implementation Plan that should be sufficient and provided a phase-in approach to permit entities to systemically implement the revised standard. The Implementation Plan for Requirement R4 has been revised to add one year to all established dates. 2. FERC Order 693 and the approved SAR assign the SDT to develop a standard with maximum allowable intervals and minimum maintenance activities. The intervals and activities specified are believed by the SDT to be technically effective, in a fashion that benefits reliability and that may be consistently monitored for compliance. 3. Please see our responses to MRO's NSRS comments on the Standard Comments.				
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Negative	The SDT has made great improvements with this Standard but please consider the following items. 1. Replace "affecting" with "protecting" in the purpose statement.

Voter	Entity	Segment	Vote	Comment
				2. 4.2.1 under Facilities, 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. Clarification is needed by the SDT that this does not include distribution assets (notwithstanding UFLS and UVLS). 3. Upon review, R1.4, R1.5, and R4.2 were added since the last posting. These are not needed and must of been added to the Standard from an outside sorce. The SDT was on the proper track to finalize this Standard. These requirements need to be left to the individual entities to determine the depth and breath of thier PMSP.
Response: **Thank you for your comments.** **1. The “Purpose” is defined by the SAR.** **2. 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 Documentation has been revised to clarify.** **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.**				
Douglas Hohlbaugh	Ohio Edison Company	4	Negative	Please see FirstEnergy's comments submitted separately through the comment period posting.
Response: **Thank you for your comments. Please see our responses to your comments submitted during the Formal Comment period.**				
John D. Martinsen	Public Utility District No. 1 of Snohomish	4	Affirmative	The overly prescriptive nature of the PRC-005-2 provides greater implementation clarity. However it may be too onerous for Local Network that have demonstrated through studies that delayed clearing (that could be attributed to protection

Voter	Entity	Segment	Vote	Comment
	County			system maintenance and testing) events do not create reliability or cascading concerns.
Response: **Thank you for your comments. PRC-005-2 is applicable to Protection Systems that are designed to provide protection for BES elements, and uses the Compliance Registry to determine applicable entities. Contributions of BES elements to cascading, etc, are immaterial in this Applicability.**				
Hao Li	Seattle City Light	4	Negative	Comment: The proposed Standard PRC-005-2 is an improvement over the previous draft in that it provides more consistency in maintenance and testing duration internals. Notwithstanding, two issues are of concern to Seattle City Light such that it is compelled to vote no: 1) the establishment of bookends for standard verification and 2) the implementation timelines for entities with systems where electro-mechanical relays still compose a significant number of components in their protection systems. Bookends: Proposed Standard PRC-005-2 specifies long inspection and maintenance intervals, up to 12 years, which correspondingly exacerbates the so-called "bookend" issue. To demonstrate that interval-based requirements have been met, two dates are needed - bookends. Evidencing an initial date can be problematic for cases where the initial date would occur prior to the effective date of a standard. NERC has provided no guidance on this issue, and the Regions approach it differently. Some, such as Texas Regional Entity, require initial dates beginning on or after the effective date of a Standard. Compliance with intervals is assessed only once two dates are available that occur on or after a standard took effect. Other regions, such as Western Electricity Coordinating Council (WECC), require that entities evidence an initial date prior to the effective date of a standard. For WECC, compliance with intervals is assessed as soon as a standard takes effect. Such variation makes application of standards involving bookends uncertain, arbitrary, capricious, and in the case of WECC, possibly illegal. Proposed Standard PRC-005-2 will be another such standard. Indeed this Standard will involve by far the largest number of bookends of any NERC standard - many thousands for a typical entity. Furthermore, the long inspection and maintenance intervals introduced in the draft will require entities in WECC, for instance, to evidence initial bookend dates prior to the date original PRC-005-1 took effect. For the 12-year intervals for CTs and VTs in proposed Standard PRC-005-2, many initial dates will occur prior to the 2005 Federal Power Act that authorized Mandatory Reliability Standards and even reach back before the 2003 blackout that catalyzed the effort to pass the Federal Power Act. As a result, many entities in WECC maybe at

Voter	Entity	Segment	Vote	Comment
				risk of being found in violation of proposed Standard PRC-005-2 immediately upon its implementation. Seattle City Light requests that NERC address the bookends issue, either within proposed Standard PRC-005-2 or in a separate, concurrent document. 2) Legacy Systems: Many entities still have legacy protection systems that rely upon electro-mechanical relays. Effective testing approaches differ between electro-mechanical and digital relay systems. Thus, although the proposed standard rightly looks to the future of digital relays by specifying testing and maintenance focused on protection systems as a whole, the proposed implementation timelines create a level of hardship for those utilities with legacy systems. In example, auxiliary relay and trip coil testing may be essential to prove the correct operation of complex, multi-function digital protection systems. However, for legacy systems with single-function electro-mechanical components, the considerable documentation and operational testing needed to implement and track such testing is not necessarily proportional to the relative risk posed by the equipment to the bulk electric system. Performance testing of electro-mechanical systems, particularly regarding control circuits, will require extensive disconnection and reconnection of portions of the circuits. Such activities will likely cause far more problems on restoration-to-service than they will locate and correct. As such, to assist entities in their implementation efforts, we believe provision of alternatives are necessary, such as additional implementation time through phasing and/or through technical feasibility exceptions.
Response: **Thank you for your comments.** **1. This issue has been addressed by NERC in Compliance Application Notice CAN-008 "PRC-005 R2 Pre-June 18 Evidence". Please see Sections 8 and 15.3 of the Supplementary Reference Document for a discussion on this topic.** **2. FERC Order 693 directs that NERC establish requirements for the maintenance of the Protection System and control circuitry is a portion thereof. Therefore, requirements for the maintenance of the control circuitry are necessary and the SDT has developed those requirements in a fashion that affords entities with the opportunity to best meet those requirements.**				
James A Ziebarth	Y-W Electric Association, Inc.	4	Negative	Y-WEA appreciates the significant amount of work that the SDT has put into this revision of the standard. It is clear that the SDT is making a sincere effort to address comments and concerns from previous revisions of this standard, and that is a good thing. While Y-WEA thanks the SDT for the straightforward honesty of disagreeing with our previous comments on the battery testing interval of 3 months for VRLA batteries, we still feel that this mandatory maximum testing interval is unreasonably short, based on IEEE 1188-2005.

Voter	Entity	Segment	Vote	Comment
				The recommended testing intervals contained in that IEEE standard should be targeted as reasonable testing intervals, with some degree of leeway allowed before any mandatory maximum interval is defined. A mandatory maximum interval of four calendar months would be much more appropriate here. This would allow a reasonable testing and maintenance program to define a standard testing interval of three months (in line with the IEEE standard) and still be able to allow a one month buffer or grace period to account for unexpected delays in testing due to extreme storms or other unanticipated heavy workloads. With the draft standard as written, a company must use an unreasonably short preferred maintenance interval if any grace period is to be built in and still remain under the mandatory maximum interval of the NERC standard. In particular, this could have a substantial impact on small companies that are distributed over a large area but have limited resources to deal with such stringent testing requirements. Because this standard will ultimately have to comply with the Regulatory Flexibility Act, it would be worthwhile for the SDT to consider the potential impacts of essentially forcing entities into much more stringent testing programs than recommended by current technically-derived and peer reviewed and approved standards such as IEEE 1188-2005. Other than that, Y-WEA sincerely appreciates the clarity that has been added to this standard over that contained in previous versions of the testing and maintenance standards. This will give registered entities much more guidance as to what NERC's and the regional entities' expectations are when it comes to protection system testing and maintenance programs.
Response: **Thank you for your comments. The SDT has revised the 3-month interval specified for VRLA batteries for some activities to 6 months.**				
Francis J. Halpin	Bonneville Power Administration	5	Negative	Please see BPA's comments submitted seperately
Response: **Thank you for your comments. Please see our responses to your comments submitted during the Formal Comment period.**				
Wilket (Jack) Ng	Consolidated Edison Co. of New York	5	Negative	The Tables – 1. 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

Voter	Entity	Segment	Vote	Comment
				Electromechanical Relays, etc. This will lengthen the standard, but will simplify reading and referring to the tables, and eliminate confusion when looking for information. 2. The “Note” included in the heading is also not necessary. “Attributes” is also not necessary in the column heading, “Component” suffices. Other Comments - 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. 3. 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. 4. 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. 5. 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? 6. 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

Voter	Entity	Segment	Vote	Comment
				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. 7. 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. 8. A control circuit is not a component, it is made up of components. 9. 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. 10. 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. 11. 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. 12. 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.

Response: **Thank you for your comments.**

1. **The SDT believes that the table headings are appropriate as reflected in the draft standard.**

2. **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 to 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.**

Voter	Entity	Segment	Vote	Comment
3. 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. 4. 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 can maintain these devices more frequently if you desire. 5. With respect to dc supply associated only with communication 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 have been considered within that activity. 6. 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 used here. They are defined only for clarify within this standard. 7. 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. 8. For purposes of this standard, the control circuit is defined as one component type. 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. 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. 11. Table 1-4 has been further modified for clarity. 12. In response to many comments, including yours, the SDT has removed 4.2.5.5 from the Applicability of the standard.				
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Negative	Constellation Power Generation is voting against this standard for the following reasons: 1. The applicability has included more generation protective components. The current PRC-005 guidance states that only Station Service transformers for plants 75 MVA and up should be included. The proposed

Voter	Entity	Segment	Vote	Comment
				standard includes all station service transformers, regardless of plant size or connection (via generator or system). Constellation Power Generation does not see the reliability benefits of this increased scope. 2. R1.4 states that all monitoring attributes of all components must be listed and identified. For most generation facilities, it is more efficient to calibrate/check the entire protective system while the plant is in an outage, regardless of a component's monitoring capabilities. This requirement would require those facilities to maintain a list of attributes that won't ever be used, and would not alter their testing frequency. What if an entity were found non-compliant in the situation that was just described? It does not affect the reliability of the BES and therefore R1.4 should be removed. 3. M1 doesn't include a measure for R1.4. It just implies that a facility must maintain a list. 4. The battery listing in the attached table is still too prescriptive. If unmonitored, there should be a quarterly and yearly check, which is implied, but it is then broken out by battery type to be more prescriptive. 5. PTs and CTs are mentioned, but it seems as though the drafting team wants a facility to only test the outputs to ensure they are working properly. To clarify this, Constellation Power Generation suggests rewording the testing verbiage for PTs and CTs.
Response: **1. Section 4.2.5 of "Applicability" specifies that only Generation Facilities that are part of the BES are included.** **2. 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. However, in consideration to your comment the SDT has revised Requirement R1, Part 1.4 and has also removed Requirement R2 because of redundancy to Requirement R1, Part 1.4.** **3. Measure M1 has been revised in consideration of your comment.** **4. The activities for different battery types are addressed separately because the relevant activities differ.** **5. 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.**				
James B Lewis	Consumers Energy	5	Negative	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 tripping customers. The standard

Voter	Entity	Segment	Vote	Comment
				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. 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: **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 Clause 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.**				
Mike Garton	Dominion Resources, Inc.	5	Negative	Dominion is opposed to this version because Requirement R1.5 is overly prescriptive, requiring an extraordinary level of documentation, with little anticipated improvement in 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.**				

Voter	Entity	Segment	Vote	Comment
Stanley M Jaskot	Entergy Corporation	5	Negative	The restructured tables are generally much clearer and the SDT is to be commended on their efforts. 1. 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 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? 2. 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? 3. 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 for a component type besides protective relays. Adding Requirement 1.5 is a significant revision and raises questions as to how

Voter	Entity	Segment	Vote	Comment
				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.** **1. The Maximum Maintenance Interval column entry in Table 2 has been revised to state, "When alarm producing Protection System component is verified" to clarify 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 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.**				
Kenneth Dresner	FirstEnergy Solutions	5	Negative	Please see FirstEnergy's comments submitted separately through the comment period posting
Response: **Thank you for your comments. Please see our responses to your comments submitted during the formal comment period.**				
David Schumann	Florida Municipal Power Agency	5	Negative	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 circuity, 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.

Voter	Entity	Segment	Vote	Comment
				Unlike Transmission and Generation Protection Systems which are needed to clear a fault and 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 the VRF of R1 should be Low since the attached tables are essentially the PSMP.

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 related 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. However, the SDT has made modifications to Applicability 4.2.1.

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

Voter	Entity	Segment	Vote	Comment
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 the gap.				
Rex A Roehl	Indeck Energy Services, Inc.	5	Negative	The level of detail for every conceivable component of every conceivable protective system does not relate to improving reliability. For some protective systems on some equipment, following these requirements, which is undoubtedly already done, will result in good reliability, but probably not improve reliability. Applying those same requirements to the thousands, if not millions, of other protective systems with generate significant costs, generate significant numbers of violations and not have any significant impact on reliability. The costs of this type of program cannot be justified unless there is an NRC mandate or a pass through to ratepayers. Most of the industry will take the cost of this program directly from the bottom line. For minimal reliability improvement, that is not appropriate under the FPA Section 215.
Response: **Thank you for your comments. FERC Order 693 and the approved SAR assign the SDT to develop a standard with maximum allowable intervals and minimum maintenance activities. The intervals and activities specified are believed by the SDT to be technically effective, in a fashion that benefits reliability and that may be consistently monitored for compliance.**				
Dennis Florom	Lincoln Electric System	5	Affirmative	While the proposed draft of the standard is acceptable as currently written, LES would like the drafting team to consider the following comments. (1) Table 1-1 should state "Test and calibrate (if necessary)" in the first section under activities. If a relay passes the test, there is no need to calibrate it. Therefore, not all relays will require calibration. (2) Please explain the drafting team's reason for not checking the trip coils of breakers in the UFLS/UVLS schemes but ensuring that all others are operated every six years. It would appear that they can all be lumped into the same group one way or another. (3) In regards to Specific Gravity Testing, many people do not perform the specific gravity test routinely if they perform the individual cell internal ohmic test routinely. LES asks the drafting team to consider allowing the internal cell ohmic test as a substitute for the specific gravity test.
Response: **Thank you for your comments.** 1. **Table 1-1 has been modified as you suggest.** 2. **This is an intentional difference between UFLS/UVLS and the remainder of the Protection Systems addressed within the Standard, because of the distributed nature of UFLS/UVLS and because these devices are usually tripping distribution system elements.** 3. **Table 1-4 does not specify specific gravity testing.**				
Mike Laney	Luminant Generation	5	Negative	Luminant commends the PRC-005-2 Standard Drafting Team for its quality efforts in producing this version of the Standard however; Luminant must cast a negative

Voter	Entity	Segment	Vote	Comment
	Company LLC			ballot vote for this present version of the Standard. The negative vote against the present version of PRC-005-2 is solely based on the addition of Requirement R1 Part 1.5 with its associated reference to it in Requirement R4 Part 4.2 and the VSL table. It is Luminant's opinion that this new Requirement as written subjects all Transmission Owners, Generation Owners and Distribution Providers to vague interpretations of a requirement that cannot be complied with because it is impossible for any of them to draft the necessary documentation to be compliant with the Standard. As stated in the High VSL associated with Part 1.5 of Requirement R1 all owners will fail "to establish calibration tolerance or equivalent parameters to determine if every individual discrete piece of equipment in a Protection System is within acceptable parameters." It is Luminant's opinion that the measurement of acceptable performance during maintenance and testing activities can be accomplished with a Pass/Fail type of documentation on a test form. No company can effectively establish calibration tolerance parameters for an entire "component type" of the Protection System. Doing so could be detrimental to the reliability of the grid. Parameters are dependent on the location, application and situation specific to each Protection System device. The inclusion of Part 1.5 of Requirement R1 is a significant addition to the standard, and by NERC Rules of Procedure requires the input and consideration of the full Standard Drafting Team.
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.**				
Wayne Lewis	Progress Energy Carolinas	5	Negative	1. Implementation Plan for PRC-005-2 Since R2, R3, and R4 requirements would be performed after establishment of the program documentation, an additional year should be added to all implementation dates for Requirements R2, R3, and R4 as shown below: • Maintenance on components with intervals less than one year must be completed within two years after applicable regulatory approval (within one year of completion of R1 Program Documentation). • Maintenance on components with intervals between one year and two years must be completed within three years after applicable regulatory approval (within two years of completion of R1 Program

Voter	Entity	Segment	Vote	Comment
				Documentation). • Maintenance on components with intervals of six years must be completed within three-, five-, and seven-year milestones after applicable regulatory approval (within two, four, and six years of completion of R1 Program Documentation). • Maintenance on components with intervals of twelve years must be completed within five-, nine-, and thirteen-year milestones after applicable regulatory approval (within four, eight, and twelve years of completion of R1 Program Documentation). 2. Standard PRC-005-02 1. Table 1-2: Rows 1 and 2 require different intervals for the activity “Verify essential signals to and from Protection System components.” Unless these inputs and outputs are monitored for Row 2, it would seem that they should be performed at the same interval for both Rows 1 and 2. Therefore, EITHER: 1. Row 1 should be broken into the following three activities: • 3 months - Verify communications system is functional • 6 years - Verify channel meets performance criteria • 12 years - Verify essential signals to and from other Protection System components OR: 2. Row 2 should be broken into the following two activities: 1. 12 years - Verify channel meets performance criteria 2. 6 years - Verify essential signals to and from other Protection System components 2. 3. Table 1-4: Only Row 1 addresses dc supplies associated with UFLS or UVLS systems. All other rows state that UFLS or UVLS systems are excluded. What is required to “Verify dc supply voltage” for the UFLS/UVLS systems? Does it require that the overall station battery voltage be checked or just the dc voltage available to the UFLS/UVLS circuit of interest? If a voltage measurement is taken at the UFLS/UVLS circuit (e.g., in distribution breaker cabinet), can the batteries/chargers at these facilities be excluded from the PRC-005-2 scope as long as they do not also supply transmission-related protection? 4. PRC-005-2 FAQ’s Document Section V.1.A, Example #2: The instrument transformer should be classified as “unmonitored” not “monitored.”

Response: **Thank you for your comments.**

1. **The Implementation Plan for Requirement R1 has been changed from 12 months to 15 months in consideration of your comment. The Implementation Plan for Requirement R4 has been revised to add one year to all established dates.**
2. **The first and second rows differ in that the first row is for unmonitored communications systems, and the second row is for monitored communications systems. The activities in both rows are appropriate and correct.**

Voter	Entity	Segment	Vote	Comment
3. Table 1-4 has been completely re-structured. For station dc supply for only UFLS/UVLS, the only activity is to verify the dc voltage. **4. 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.**				
Jerzy A Slusarz	PSEG Power LLC	5	Negative	The PSEG Companies do not agree with the Facilities as currently described in section 4.2.5.5. Please refer to detailed comments provided in the formal Comment Form.
Response: Thank you for your comments. Please see our response to your detailed comments from the formal comment period.				
Steven Grega	Public Utility District No. 1 of Lewis County	5	Negative	Do not like the word "all" in the proposed standard. Does all components mean each piece of wire is included? Engineers are conservative in their protection system designs and have redundant relays and protection paths. Even with half the relays out of service, protection is normally retained. Would want to have 80% a compliance level with a year to test & maintenance any component testing founded to be non-compliant. This proposed standard will ensure many more violations.
Response: Thank you for your comments. The approved PRC-005-1 already requires that entities have a program to maintain their Protection System and implement that program. This already implies, "all", therefore PRC-005-2 should not have the impact suggested by your comment.				
Michael J. Haynes	Seattle City Light	5	Negative	The proposed Standard PRC-005-2 is an improvement over the previous draft in that it provides more consistency in maintenance and testing duration internals. Notwithstanding, two issues are of concern to Seattle City Light such that it is compelled to vote no: 1. the establishment of bookends for standard verification and 2) the implementation timelines for entities with systems where electro-mechanical relays still compose a significant number of components in their protection systems. Bookends: Proposed Standard PRC-005-2 specifies long inspection and maintenance intervals, up to 12 years, which correspondingly exacerbates the so-called "bookend" issue. To demonstrate that interval-based requirements have been met, two dates are needed - bookends. Evidencing an initial date can be problematic for cases where the initial date would occur prior to the effective date of a standard. NERC has provided no guidance on this issue, and the Regions approach it differently. Some, such as Texas Regional Entity, require initial dates beginning on or after the effective date of a Standard. Compliance with intervals is assessed only once two dates are available that occur on or after a standard took effect. Other regions, such as Western Electricity Coordinating Council (WECC), require

Voter	Entity	Segment	Vote	Comment
				that entities evidence an initial date prior to the effective date of a standard. For WECC, compliance with intervals is assessed as soon as a standard takes effect. Such variation makes application of standards involving bookends uncertain, arbitrary, capricious, and in the case of WECC, possibly illegal. Proposed Standard PRC-005-2 will be another such standard. Indeed this Standard will involve by far the largest number of bookends of any NERC standard - many thousands for a typical entity. Furthermore, the long inspection and maintenance intervals introduced in the draft will require entities in WECC, for instance, to evidence initial bookend dates prior to the date original PRC-005-1 took effect. For the 12-year intervals for CTs and VTs in proposed Standard PRC-005-2, many initial dates will occur prior to the 2005 Federal Power Act that authorized Mandatory Reliability Standards and even reach back before the 2003 blackout that catalyzed the effort to pass the Federal Power Act. As a result, many entities in WECC maybe at risk of being found in violation of proposed Standard PRC-005-2 immediately upon its implementation. Seattle City Light requests that NERC address the bookends issue, either within proposed Standard PRC-005-2 or in a separate, concurrent document. 2. Legacy Systems: Many entities still have legacy protection systems that rely upon electro-mechanical relays. Effective testing approaches differ between electro-mechanical and digital relay systems. Thus, although the proposed standard rightly looks to the future of digital relays by specifying testing and maintenance focused on protection systems as a whole, the proposed implementation timelines create a level of hardship for those utilities with legacy systems. In example, auxilary relay and trip coil testing may be essential to prove the correct operation of complex, multi-function digital protection systems. However, for legacy systems with single-function electro-mechnical compenents, the considerable documentation and operational testing needed to implement and track such testing is not necessarily proporational to the relative risk posed by the equipment to the bulk electric system. Performance testing of electro-mechanical systems, particularly regarding control circuits, will require extensive disconnection and reconnection of portions of the circuits. Such activities will likely cause far more problems on restoration-to-service than they will locate and correct. As such, to assist entities in their implementation efforts, we believe provision of alternatives are necessary, such as additional implementation time through phasing and/or through technical feasability exceptions.

Voter	Entity	Segment	Vote	Comment
Response: Thank you for your comments. 1. This issue has been addressed by NERC in Compliance Application Notice CAN-008 "PRC-005 R2 Pre-June 18 Evidence". 2. Please see Sections 8 and 15.3 of the Supplementary Reference Document for a discussion on this topic. FERC Order 693 directs that NERC establish requirements for the maintenance of the Protection System and control circuitry is a portion thereof. Therefore, requirements for the maintenance of the control circuitry are necessary and the SDT has developed those requirements in a fashion that affords entities with the opportunity to best meet those requirements.				
William D Shultz	Southern Company Generation	5	Negative	Please see comments submitted via the electronic comment form.
Response: Thank you for your comments. Please see our responses to your comments from the formal comment period.				
George T. Ballew	Tennessee Valley Authority	5	Negative	Project 2007-17 Protection System Maintenance for Standard PRC-005-2 Draft - NERC is recommending 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 NO because of the hurried fashion it is being commented, voted, and reviewed. Official comments to the document were entered on the NERC Portal.
Response: Thank you for your comments. Please see our responses to your comments from the formal comment period.				
Melissa Kurtz	U.S. Army Corps of Engineers	5	Negative	Paragraph 4.2.5.4 - The standard should be changed to require station service transformers only if they will cause a loss of the generator tied to the BES. Also recommend a definition of station service - we have station service that if lost would not negatively effect the BES.
Response: Thank you for your comments. Clause 4.2.5.5 has been removed. Generator-connected station service transformers are essential to the continuing operation of the generation plant; therefore, protection on these system components is included within PRC-005-2 if the generation plant is a BES facility.				
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Negative	1. 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. 2. The supplemental reference provides significant clarity to the intent 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

Voter	Entity	Segment	Vote	Comment
				into the text of the standard. 3.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 was introduced. Additional related to this practice are included later on. 4. 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. 5. 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. 6. 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 the "voltage and current sensing devices". 7.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. 8. Protection System Maintenance Program (PSMP) definition: The Restore bullet should be revised to read as follows: "Return malfunctioning components to

Voter	Entity	Segment	Vote	Comment
				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." 9.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. a. 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. 10. 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. 11. 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. 12. 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. 13. Insert the phrase "Standard PRC-005-2" before the term "Tables 1-1..."

Voter	Entity	Segment	Vote	Comment
				14. 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 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 powerplant 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 powerplant 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? 15. Requirements Should the sub requirements have the "R" prefix? 16. R4. Change the phrase "... PSMP, including identification of the resolution of all ..." to read "...PSMP including identification, but not the resolution, of all ...". 17.General comment PRC005-2 is very specific in listing the

Response: Thank you for your comments.

1. The Tables do not provide a reference to either the Supplementary Reference Document or the FAQ. 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 developed in accordance with the standard and will be posted with the standard, the NERC Standard Development Procedure does require that they undergo industry review before being initially posted, and upon any revision.

2. The clarifying language is exactly that – clarifying language, and is not essential to application of the Standard. He NERC Standards Development Procedure establishes that the standard shall not include explanatory text.

3. 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.

Voter	Entity	Segment	Vote	Comment

4. "Protective relay" is defined by IEEE, and the SDT sees no need to either change the definition or to repeat the definition with PRC-005. Further, the applicability of generically-described protective relays is defined by the Applicability clause of PRC-005-2.
5. The issues raised by the FERC NOPR will be addressed as part of the response to the NOPR (and, ultimately, the Order). The extension of 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).
6. The extension of 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).
7. Definition 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.
8. The "restore" portion of PSMP specifically addresses returning malfunctioning components to your proper operation. The requirements regarding maintenance correctable issues are further addressed within that definition (for use only within PRC-005-2).
9. The SDT is currently not planning on further modifying the most recent NERC BOT-approved definition of Protection System.
10. 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.
11. 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 demonstration completion of them.
12. Since this term is used only in Attachment A, it seems unnecessary to provide the explanation requested.
13. The SDT has elected not to change the reference to the Tables throughout the Standard.
14. Thank you for your comments. Clause 4.2.5.5 has been removed. Generator-connected station service transformers are essential to the continuing operation of the generation plant; therefore, protection on these system components is included within PRC-005-2 if the generation plant is a BES facility.
15. The current style guide for NERC Standards does not preface the Parts with an "R".
16. Identifying problems, but not fixing them, does not constitute an effective program. In deference to the time that may be

Voter	Entity	Segment	Vote	Comment
necessary to repair / replace defective components, the SDT has decided to require only initiation of resolution of maintenance correctable issues, not to demonstration completion of them. **17. It appears the remainder of your comment was truncated and cannot be ascertained.**				
Linda Horn	Wisconsin Electric Power Co.	5	Negative	Q4: 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.				
Leonard Rentmeester	Wisconsin Public Service Corp.	5	Negative	1. Implementation plan is too aggressive given the drastic changes from PRC-005-1 to PRC-005-2 2. The drastic changes don't appear to provide an incremental increase in the reliability of the BES 3. We support the MRO NSRS comments
Response: Thank you for your comments. **1. The SDT has carefully considered the changes that entities will be expected to make to their program in response to PRC-005-2 and provided an Implementation Plan that should be sufficient and provided a phase-in approach to permit entities to systemically implement the revised standard. The Implementation Plan for Requirement R4 has been revised to add one year to all established dates.** **2. FERC Order 693 and the approved SAR assign the SDT to develop a standard with maximum allowable intervals and minimum maintenance activities. The intervals and activities specified are believed by the SDT to be technically effective, in a fashion that benefits reliability and that may be consistently monitored for compliance.** **3. Please see our responses to MRO's NSRS formal comments in the Consideration of Comments document.**				
Liam Noailles	Xcel Energy, Inc.	5	Negative	We feel that several improvements were made since the last draft. However, we feel that some gaps exist that should be addressed before moving this project forward. We have detailed our issues in our formal comments
Response: Thank you for your comments. Please see our response to your formal comments.				
Edward P. Cox	AEP Marketing	6	Negative	Restructured Tables: 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

Voter	Entity	Segment	Vote	Comment
				maximum interval of 6 years. AEP does not understand the rationale for the difference in intervals, when in most cases, one verifies the other. Also, unmonitored control circuitry is capitalized in row 4 such that it infers a defined term. 2. 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. 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. VSLs, VRFs and Time Horizons: 3. The VSL table should be revised to remove the reference to the Standard Requirement 1.5 in the R1 “High” VSL. 4. All four levels of the VSL for R2 make reference to a “condition-based PSMP.” However, nowhere 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. 5. 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. FAQ and Supplementary Reference: 6. 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: a. Section 5 of the Supplementary Reference, refers to “condition-based”

Voter	Entity	Segment	Vote	Comment
				maintenance programs. However, nowhere 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. b. Section 15.7, page 26, appears to have a typographical error "...can all be used as the primary action is the maintenance activity..." c. 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. "Frequently-Asked Questions": 7. 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: a. The section "Terms Used in PRC-005-2" is blank and should be removed as it adds no value. Section I.1 and Section IV.3.G reference "condition-based" maintenance programs. However, nowhere in the standard is the term "condition-based" used in reference to defining ones PSMP. b. 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. c. 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...". General: 8. 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.

Voter	Entity	Segment	Vote	Comment
				9. 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 a knowledge of material in the Supplementary Reference or FAQ. 10. "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. 11. 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: **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 circuitry. The capitalized term has been corrected.**
2. **Table 1-4 has been modified in consideration of your comments.**
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 SDT concluded that Requirement R2 is redundant to Requirement R1, Part 1.4 and has deleted Requirement R2 (together with the Measures and & VSL).**
5. **If the indicated monitoring attributes are present, no "hands-on" periodic maintenance is required, as the monitoring of the component is providing a continuing indication of its functionality.**
6. **The discussion within the Supplementary Reference Document and FAQ are informative, not normative, and thus do not belong as part of the standard.**
   a) **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.**

Voter	Entity	Segment	Vote	Comment
b) This clause has been corrected. c) A higher-quality version of Figure 2 has been substituted. 7. The discussion within the Supplementary Reference Document and FAQ are informative, not normative, and thus do not belong as part of the standard. a) 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. b) 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. c) 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. 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. 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. 10. "Protective relay" is defined by IEEE, and the SDT sees no need to either change the definition or to repeat the definition with PRC-005. Further, the applicability of generically-described protective relays is defined by the Applicability clause of PRC-005-2. 11. 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.				
Brenda S. Anderson	Bonneville Power Administration	6	Negative	Refer to BPA comments
Response: Thank you for your comments. Please see our response to the BPA comments.				
Matthew D Cripps	Cleco Power LLC	6	Negative	Cleco applies its' UFLS on the distribution grid with each UF relay individually tripping a relatively low value of load thru breakers and reclosers. Since our program is implemented via a large number of individual components, breakers, reclosers, and individual batteries, the failure of any one component will have a minimal impact on the effectiveness of the overall UFLS program within our region. Therefore, the verification of sensing devices, dc supply voltages, and the

Voter	Entity	Segment	Vote	Comment
				paths of the control circuit and trip circuits on the UFLS systems implemented on the distribution grid is unnecessary.
Response: **Thank you for your comments. The SDT disagrees; the sensing devices, control circuitry and dc supply related to UFLS has an effect on the performance of the UFLS. The SDT has, however, respected the overall impact on the control circuitry of individual UFLS on BES reliability by requiring that UFLS be subjected to a subset of the overall sensing devices, control circuitry and dc supply maintenance activities.**				
Nickesha P Carrol	Consolidated Edison Co. of New York	6	Negative	The Tables 1. 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. 2. "Attributes" is also not necessary in the column heading, "Component" suffices. Other Comments – 3. 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. 4. 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. 5. 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

Voter	Entity	Segment	Vote	Comment
				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. 6. 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? 7. 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. 8. 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. 9. A control circuit is not a component, it is made up of components. 10. 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. 11. 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. 12. 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. Regarding station service transformers, 13. 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

Voter	Entity	Segment	Vote	Comment
				(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.

Response: Thank you for your comments.

1. The SDT believes that the table headings are appropriate as reflected in the draft standard.

2. Please see the SDT's response to ISO New England Inc. in the formal Standard Comments

3. The intervals and activities specified are believed by the SDT to be technically effective, in a fashion that may be consistently monitored for compliance. Further, FERC Order 693 directs NERC to establish maximum allowable intervals, which implies that minimum activities also need to 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.

4. 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.

5. 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 can maintain these devices more frequently if you desire

6. With respect to dc supply associated only with communication 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 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.

7. 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 used here. They are defined only for clarify within this standard. The SDT will confirm with NERC staff that this approach is acceptable.

8. 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.

9. For purposes of this standard, the control circuit is defined as one component type.

Voter	Entity	Segment	Vote	Comment
10. 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. 11. 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 Please see the SDT's response to NPPC in the formal Standard Comments. 12. Table 1-4 has been further modified for clarity. 13. In response to many comments, including yours, the SDT has removed 4.2.5.5 from the Applicability of the standard.				
Brenda Powell	Constellation Energy Commodities Group	6	Negative	1. The applicability has included more generation protective components. The current PRC-005 guidance states that only Station Service transformers for plants 75 MVA and up should be included. The proposed standard includes all station service transformers, regardless of plant size or connection (via generator or system). Constellation Energy Commodities Group does not see the reliability benefits of this increased scope. 2. R1.4 states that all monitoring attributes of all components must be listed and identified. For most generation facilities, it is more efficient to calibrate/check the entire protective system while the plant is in an outage, regardless of a component's monitoring capabilities. This requirement would require those facilities to maintain a list of attributes that won't ever be used, and would not alter their testing frequency. What if an entity were found non-compliant in the situation that was just described? It does not affect the reliability of the BES and therefore R1.4 should be removed. 3. M1 doesn't include a measure for R1.4. It just implies that a facility must maintain a list. 4. The battery listing in the attached table is still too prescriptive. If unmonitored, there should be a quarterly and yearly check, which is implied, but it is then broken out by battery type to be more prescriptive. 5. PTs and CTs are mentioned, but it seems as though the drafting team wants a facility to only test the outputs to ensure they are working properly. To clarify this, Constellation Energy Commodities Group suggests rewording the testing verbiage for PTs and CTs.
Response: Thank you for your comments. 1. Section 4.2.5 of "Applicability" specifies that only Generation Facilities that are part of the BES are included. 2. 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. However, in consideration to your comment the				

Voter	Entity	Segment	Vote	Comment
SDT has revised Requirement R1, Part 1.4 and has also removed Requirement R2 because of redundancy to Requirement R1, Part 1.4. 3. Measure M1 has been revised in consideration of your comment. 4. The activities for different battery types are addressed separately because the relevant activities differ. 5. 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.				
Louis S Slade	Dominion Resources, Inc.	6	Negative	Dominion is opposed to this version because Requirement R1.5 is overly prescriptive, requiring an extraordinary level of documentation, with little anticipated improvement in 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.				
Terri F Benoit	Entergy Services, Inc.	6	Negative	The restructured tables are generally much clearer and the SDT is to be commended on their efforts. 1. 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 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? 2. 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

Voter	Entity	Segment	Vote	Comment
				the severity level(s) of a "failure to specify one (or Cthe 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? 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 for a component type besides protective relays. 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.** **1. The Maximum Maintenance Interval column entry in Table 2 has been revised to state, "When alarm producing Protection System component is verified" to clarify 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.**				
Mark S Travaglianti	FirstEnergy Solutions	6	Negative	Please see FirstEnergy's comments submitted separately through the comment period posting.
Response: **Thank you for your comments. Please see our response to your comments submitted separately through the formal comment period.**				
Richard L. Montgomery	Florida Municipal Power Agency	6	Negative	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.

Voter	Entity	Segment	Vote	Comment
				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 circuity, 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 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 the VRF of R1 should be Low since the attached tables are essentially the PSMP.

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**

Voter	Entity	Segment	Vote	Comment
excludes UFLS and UVLS from maintenance activities related 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. However, the SDT has made changes to Applicability 4.2.1.** **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 the gap.**				
Thomas E Washburn	Florida Municipal Power Pool	6	Negative	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 circuity, 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 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, 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

Voter	Entity	Segment	Vote	Comment
				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 the VRF of R1 should be Low since the attached tables are essentially the PSMP.
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 related 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. However, the SDT has made changes to Applicability 4.2.1.** 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 the gap.**				
Silvia P Mitchell	Florida Power & Light Co.	6	Negative	This draft standard is too perscriptive. 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

Voter	Entity	Segment	Vote	Comment
				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.** **2. 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.** **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. The standard has been revised as you suggested.**				
Paul Shipps	Lakeland Electric	6	Negative	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.)
Response: **Thank you for your comments. 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.**				
Eric Ruskamp	Lincoln Electric System	6	Affirmative	While the proposed draft of the standard is acceptable as currently written, LES would like the drafting team to consider the following comments. (1) Table 1-1 should state "Test and calibrate (if necessary)" in the first section under activities. If a relay passes the test, there is no need to calibrate it.

Voter	Entity	Segment	Vote	Comment
				Therefore, not all relays will require calibration. (2) Please explain the drafting team's reason for not checking the trip coils of breakers in the UFLS/UVLS schemes but ensuring that all others are operated every six years. It would appear that they can all be lumped into the same group one way or another. (3) In regards to Specific Gravity Testing, many people do not perform the specific gravity test routinely if they perform the individual cell internal ohmic test routinely. LES asks the drafting team to consider allowing the internal cell ohmic test as a substitute for the specific gravity test.
Response: **Thank you for your comments.** 1. **Table 1-1 has been modified as you suggest.** 2. **This is an intentional difference between UFLS/UVLS and the remainder of the Protection Systems addressed within the Standard, because of the distributed nature of UFLS/UVLS and because these devices are usually tripping distribution system elements.** 3. **Table 1-4 does not specify specific gravity testing.**				
Brad Jones	Luminant Energy	6	Negative	Luminant commends the PRC-005-2 Standard Drafting Team for its quality efforts in producing this version of the Standard however; Luminant must cast a negative ballot vote for this present version of the Standard. The negative vote against the present version of PRC-005-2 is solely based on the addition of Requirement R1 Part 1.5 with its associated reference to it in Requirement R4 Part 4.2 and the VSL table. It is Luminant's opinion that this new Requirement as written subjects all Transmission Owners, Generation Owners and Distribution Providers to vague interpretations of a requirement that cannot be complied with because it is impossible for any of them to draft the necessary documentation to be compliant with the Standard. As stated in the High VSL associated with Part 1.5 of Requirement R1 all owners will fail "to establish calibration tolerance or equivalent parameters to determine if every individual discrete piece of equipment in a Protection System is within acceptable parameters." It is Luminant's opinion that the measurement of acceptable performance during maintenance and testing activities can be accomplished with a Pass/Fail type of documentation on a test form. No company can effectively establish calibration tolerance parameters for an entire "component type" of the Protection System. Doing so could be detrimental to the reliability of the grid. Parameters are dependent on the location, application and situation specific to each Protection System device.

Voter	Entity	Segment	Vote	Comment
				The inclusion of Part 1.5 of Requirement R1 is a significant addition to the standard, and by NERC Rules of Procedure requires the input and consideration of the full Standard Drafting Team.
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.**				
Daniel Prowse	Manitoba Hydro	6	Negative	1. Implementation Plan (Timeline) for R1: In areas not requiring regulatory approval, the 6 month time frame proposed for R1 is not achievable and is not consistent with areas requiring regulatory approval. To be consistent, the effective 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. 2. VSLs: 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. 3. Table 1-4: The requirements for batteries listed in Table 1-4 do not appear to be consistent with the comments in the FAQ Section (V 1A Example 1). Please see comments submitted during the formal comment period for further detail. 4. Table 1-4: 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.
Response: **Thank you for your comments.** **1. In consideration of your comment, "six" has been modified to "twelve" in the Implementation Plan for R1, making it consistent with the remainder of the Implementation Plan.** **2. The SDT does not understand your concern; further details are needed.** **3. 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.** **4. The SDT believes that the 3-month interval specified in the Standard is appropriate.**				
Joseph O'Brien	Northern Indiana Public Service Co.	6	Negative	We disagree with the practice of performing calibration checks on non microprocessor relays every 6 years.
Response: **Thank you for your comments. The SDT considers it important that calibration checks be performed on non microprocessor relays no less frequently than every 6 years.**				

Voter	Entity	Segment	Vote	Comment
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Negative	The PSEG Companies do not agree with the Facilities as currently described in section 4.2.5.5. Please refer to detailed comments provided in the formal Comment Form.
Response: **Thank you for your comments. Please see our response to your comments from the formal comment period.**				
Dennis Sismaet	Seattle City Light	6	Negative	The proposed Standard PRC-005-2 is an improvement over the previous draft in that it provides more consistency in maintenance and testing duration internals. Notwithstanding, two issues are of concern to Seattle City Light such that it is compelled to vote no: 1) the establishment of bookends for standard verification and 2) the implementation timelines for entities with systems where electro-mechanical relays still compose a significant number of components in their protection systems. 1. Bookends: Proposed Standard PRC-005-2 specifies long inspection and maintenance intervals, up to 12 years, which correspondingly exacerbates the so-called "bookend" issue. To demonstrate that interval-based requirements have been met, two dates are needed - bookends. Evidencing an initial date can be problematic for cases where the initial date would occur prior to the effective date of a standard. NERC has provided no guidance on this issue, and the Regions approach it differently. Some, such as Texas Regional Entity, require initial dates beginning on or after the effective date of a Standard. Compliance with intervals is assessed only once two dates are available that occur on or after a standard took effect. Other regions, such as Western Electricity Coordinating Council (WECC), require that entities evidence an initial date prior to the effective date of a standard. For WECC, compliance with intervals is assessed as soon as a standard takes effect. Such variation makes application of standards involving bookends uncertain, arbitrary, capricious, and in the case of WECC, possibly illegal. Proposed Standard PRC-005-2 will be another such standard. Indeed this Standard will involve by far the largest number of bookends of any NERC standard - many thousands for a typical entity. Furthermore, the long inspection and maintenance intervals introduced in the draft will require entities in WECC, for instance, to evidence initial bookend dates prior to the date original PRC-005-1 took effect. For the 12-year intervals for CTs and VTs in proposed Standard PRC-005-2, many initial dates will occur prior to the 2005 Federal Power Act that authorized Mandatory Reliability Standards and even reach back before the 2003 blackout that catalyzed the effort to pass the Federal Power Act. As a result, many entities

Voter	Entity	Segment	Vote	Comment
				in WECC maybe at risk of being found in violation of proposed Standard PRC-005-2 immediately upon its implementation. Seattle City Light requests that NERC address the bookends issue, either within proposed Standard PRC-005-2 or in a separate, concurrent document. 2. Legacy Systems: Many entities still have legacy protection systems that rely upon electro-mechanical relays. Effective testing approaches differ between electro-mechanical and digital relay systems. Thus, although the proposed standard rightly looks to the future of digital relays by specifying testing and maintenance focused on protection systems as a whole, the proposed implementation timelines create a level of hardship for those utilities with legacy systems. In example, auxilary relay and trip coil testing may be essential to prove the correct operation of complex, multi-function digital protection systems. However, for legacy systems with single-function electro-mechanical components, the considerable documentation and operational testing needed to implement and track such testing is not necessarily proportional to the relative risk posed by the equipment to the bulk electric system. Performance testing of electro-mechanical systems, particularly regarding control circuits, will require extensive disconnection and reconnection of portions of the circuits. Such activities will likely cause far more problems on restoration-to-service than they will locate and correct. As such, to assist entities in their implementation efforts, we believe provision of alternatives are necessary, such as additional implementation time through phasing and/or through technical feasibility exceptions.
Response: **Thank you for your comments.** **1. This issue has been addressed by NERC in Compliance Application Notice CAN-008 "PRC-005 R2 Pre-June 18 Evidence".** **2. Please see Sections 8 and 15.3 of the Supplementary Reference Document for a discussion on this topic. FERC Order 693 directs that NERC establish requirements for the maintenance of the Protection System and control circuitry is a portion thereof. Therefore, requirements for the maintenance of the control circuitry are necessary and the SDT has developed those requirements in a fashion that affords entities with the opportunity to best meet those requirements.**				
David F. Lemmons	Xcel Energy, Inc.	6	Negative	We feel that several improvements were made since the last draft. However, we feel that some gaps exist that should be addressed before moving this project forward. We have detailed our issues in our formal comments.
Response: **Thank you for your comments. Please see our responses to your formal comments.**				
Jim R Stanton	SPS Consulting Group Inc.	8	Negative	1. The standard as written is wildly prescriptive and violates the concept of "what and not how." The standard and its Tables seek to prescribe in detail maintenance and testing processes which should be left up to the owners and operators of the protection systems.

Voter	Entity	Segment	Vote	Comment
				2. References to Tables 1-5 should be deleted from the standard itself and moved to a reference section.
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 to be prescribed. If an entities' experience is that components require less-frequent maintenance, a performance-based program in accordance with Requirement R3 and Attachment A is an option.** 2. **Tables 1-1 through 1-5 are considered by the SDT to be an integral part of the requirements of the standard and thus belong within the Standard.**				
Louise McCarren	Western Electricity Coordinating Council	10	Affirmative	Our affirmative vote reflects our belief that the proposed PRC-005-2 is an overall improvement to the four standards that it would replace. We also believe that it is appropriate to address maintenance and testing of all protection systems in one standard rather than in four individual standards.
Response: **Thank you for your comments and support.**				

END OF REPORT